TATE OF CALIFORNIA EDMUND Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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May 19, 2016

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 14-11-003, APPLICATION 14-11-004:

This is the proposed decision of Administrative Law Judges John S. Wong and Rafael L. Lirag. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's June 23, 2016, Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ RICHARD SMITH for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

Decision **PROPOSED DECISION OF ALJs WONG and LIRAG**
(Mailed 5/19/16)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2016.	Application 14-11-003 (Filed November 14, 2014)
And Related Matter.	Application 14-11-004

(See Appendix D for Service List)

DECISION ADDRESSING THE GENERAL RATE CASES OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY AND THE PROPOSED SETTLEMENTS

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DECISION ADDRESSING THE GENERAL RATE CASES OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY AND THE PROPOSED SETTLEMENTS

Summary

Today's decision addresses the test year (TY) 2016 general rate case (GRC) applications of San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas).[1]

As updated by SDG&E and SoCalGas in its update testimony, SDG&E requested a TY 2016 revenue requirement of $1,895,437,000 ($324,188,000 for gas operations, and $1,571,249,000 for electric operations), and SoCalGas requested a TY 2016 revenue requirement of $2,331,187,000.[2]

Prior to the settlement negotiations in these proceedings, the Office of Ratepayer Advocates (ORA) and other parties, recommended that adjustments be made to the GRC requests of both SDG&E and SoCalGas. The positions of SDG&E, SoCalGas, and the other parties were fully litigated in evidentiary hearings held in June and July of 2015.

Following the evidentiary hearings, SDG&E, SoCalGas, and various other parties held settlement discussions. These discussions resulted in the filing of motions to adopt proposed settlements to resolve most of the issues in the GRC applications of SDG&E and SoCalGas. For SDG&E, the proposed settlement recommends, among other things, that a test year 2016 revenue requirement of

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[1] A Glossary of the abbreviations used in this decision is attached to this decision as Appendix C.

[2] In their applications filed on November 14, 2014, SDG&E originally requested a revenue requirement of $1.911 billion ($326 million for gas operations, and $1.585 billion for electric operations), and SoCalGas originally requested a revenue requirement of $2.4 billion.

$1,810,533,000 ($310.487 million for gas operations, and $1.500 billion for electric operations) be adopted. For SoCalGas, the proposed settlement recommends, among other things, that a test year 2016 revenue requirement of $2,219,426,000 be adopted.

Today's decision adopts all of the proposed settlements contained in the separate motions to adopt the proposed settlements in SDG&E's GRC application, and in SoCalGas's GRC application. However, we make two income tax related adjustments to the revenue requirements adopted in today's decision, and one adjustment to SDG&E's offsite storage costs related to the San Onofre Nuclear Generating Station (SONGS). The first adjustment is for the repairs deduction issue, which the settlement parties agreed would be separately considered apart from the settlements, and recognized that the revenue requirement could change as a result of that issue. The second adjustment is for bonus depreciation, which ORA's settlement agreement with SDG&E and SoCalGas resolves, but which we determine is unreasonable. The third adjustment removes the SONGS offsite storage cost from the revenue requirement because that cost has been resolved in a different proceeding.

With these three adjustments, today's decision adopts a test year 2016 revenue requirement of $1,789,286,000 for SDG&E's combined operations ($1,482,033,000 for its electric operations, and $307,253,000 for its gas operations).[3] The adopted revenue requirement for SDG&E is $106 million lower than what SDG&E had requested ($1.895 billion) in its update testimony.

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[3] Appendix A of this decision reflects the revenue requirements adopted for SoCalGas and SDG&E. Appendix B of this decision reflects the adjustments made to the adopted revenue requirements by this decision.

Today's adopted base margin 2016 revenue requirement represents a $48 million increase over SDG&E's currently authorized base margin revenue requirement of $1,721,266,000.

For SoCalGas, with the adjustments for the repairs deduction and bonus depreciation, we adopt a test year 2016 revenue requirement of $2,199,194,000 for SoCalGas. Today's adopted 2016 revenue requirement is $132 million lower than what SoCalGas had requested ($2.331 billion) in its update testimony, and the adopted base margin 2016 revenue requirement is a $104.030 million increase over SoCalGas' currently authorized base margin revenue requirement of $1,966,480,000.

Since the adjustments for bonus depreciation and the SONGS offsite storage cost were addressed in ORA's settlement agreement with SDG&E, and the bonus depreciation was addressed in ORA's settlement agreement with SoCalGas, those adjustments alter what was agreed to as part of those two settlements. Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, we will allow the settling parties to respond within 15 days of the adoption of today's decision to accept the two adjustments for SDG&E, and to accept the bonus depreciation adjustment for SoCalGas.

The motion filed by ORA, SDG&E and SoCalGas to adopt the proposed settlement to add an additional attrition year (2019) to the test year 2016 GRC cycle of SDG&E and SoCalGas is denied.

As part of ORA's settlement with SDG&E and SoCalGas, the revenue requirements for the post-test years of 2017 and 2018 will be adjusted by a 3.5% increase in 2017, and an additional 3.5% increase in 2018.

It is estimated for a typical electric residential customer of SDG&E using 500 kilowatt hours of electricity per month, the customer's monthly electric rate will increase by about $1.36 per month, or 1.2%, from $110.08 to $111.44.

For an SDG&E natural gas customer using 26 therms of gas per month, it is estimated that the customer's monthly gas bill will increase by about $0.05 per month, a 0.2% increase in the monthly gas bill.

For a SoCalGas gas customer using 37 therms of gas per month, it is estimated that the customer's monthly gas bill will increase by about $1.29 per month, a 3.2% increase in the monthly gas bill.

The other issues resolved in this proceeding through today's decision include the following:

- The adopted revenue requirement, and post-test year increases, will provide the necessary funds to allow SDG&E to operate its electric and natural gas transmission and distribution system safely and reliably at reasonable rates.
- The adopted revenue requirement, and post-test year increases, will provide the necessary funds to allow SoCalGas to operate its natural gas transmission, gas distribution, and gas storage systems safely and reliably at reasonable rates.
- As part of the agreed upon settlement amounts, $38.381 million is provided for operating and maintenance costs, and a total of $236 million for capital improvements over the GRC cycle, for SoCalGas' underground storage facilities, including funds for its storage integrity management program (SIMP).
- 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.
- SDG&E is prohibited from compensating its employees, managers, and executives from variable compensation that is based on SDG&E's recovery of monies from ratepayers for the

wildfire costs that are being litigated before the Commission in Application 15-09-010.

- For the TY 2016 GRC cycle, SoCalGas is prevented from awarding variable compensation to its non-represented employees and executives for activities related to its underground gas storage facilities or at Aliso Canyon unless it has taken into consideration the detrimental effects of the Aliso Canyon leak as a full or partial offset to such an award.
- Pursuant to Pub. Util. Code § 706, requires SDG&E and SoCalGas to establish memorandum accounts to track the compensation of its officers authorized in this decision, and the compensation paid or owed to its officers, and to follow the requirements of this code section if SDG&E or SoCalGas seeks to have ratepayers pay for the "excess compensation" that may have been paid to or is owed to an officer in connection with of a "triggering event."
- SoCalGas is to separate out the costs related to the Aliso Canyon leak in its next GRC to ensure that none of those costs are reflected in the TY 2019 revenue requirement.
- Provides the necessary funds for SDG&E and SoCalGas to perform the pipeline inspection, testing, and maintenance work on their gas transmission and distribution pipelines as required by the federal government.
- Provides the necessary funds to maintain and replace aging electric and gas delivery infrastructure so as to ensure the safe and reliable delivery of electricity and natural gas to customers.
- Provides the necessary funds to comply with state and federal environmental regulations.
- To lessen the danger of wildfires, provides the necessary funds to allow SDG&E to trim trees and brush away from overhead electric lines, and to replace many of its wooden poles with steel poles.
- Adopts the other settlements between SDG&E, SoCalGas, and various other parties on issues such as: balancing account treatment for pension and other benefits; compliance with

statutes regarding methane leakage provisions; continue to discuss a plan to repair non-hazardous leaks; developing avenues to increase the participation of diverse businesses and underrepresented individuals in the procurement and workforce needs of the utilities; maintaining balancing accounts for the integrity management programs associated with transmission and distribution pipelines, and for the storage integrity management program of SoCalGas.

1. Procedural Background

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas)[4] filed separate general rate case (GRC) applications with the Commission on November 14, 2014.[5] On December 26, 2014, the two applications were consolidated.

On December 18, 2014, The Utility Reform Network (TURN) filed a motion requesting that SDG&E and SoCalGas be directed to establish memorandum accounts to track the income tax differences associated with the changes for the accounting of deductions for repairs. In a January 15, 2015 ruling, TURN's motion was granted, and SDG&E and SoCalGas were each directed to file advice letters to establish a repairs deduction memorandum account, to take effect on January 15, 2015, until a decision is adopted on the Test Year (TY) 2016 applications of SDG&E and SoCalGas. On July 23, 2015, the Commission approved the advice letters of SDG&E and SoCalGas establishing those memorandum accounts.

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[4] At times, we refer to SDG&E and SoCalGas in this decision as the "Applicants."

[5] "Commission" refers to the California Public Utilities Commission. In the citation to case decisions, the Commission is abbreviated as "PUC." References to the Public Utilities Code are abbreviated as "Pub. Util. Code."

After the filing of protests and responsive pleadings to the two applications, a prehearing conference (PHC) was held on January 8, 2015. Following the PHC, the procedural schedule for these consolidated proceedings was addressed in the February 5, 2015 scoping memo and ruling (scoping ruling) of the assigned Commissioner.

On March 13, 2015, SDG&E and SoCalGas filed a joint motion requesting that they be allowed to establish GRC memorandum accounts to record the difference between the rates in effect beginning January 1, 2016, and the rates to be adopted in these proceedings in the event a final Commission decision is not rendered in time for the 2016 rates to take effect January 1, 2016. In Decision (D.) 15-05-044, the Commission granted the request of SDG&E and SoCalGas to establish their respective memorandum accounts.

Six public participation hearings (PPHs) were then held for SoCalGas, and four PPHs were held for SDG&E in May and June of 2015. In addition to the PPHs, a number of letters and e-mails regarding the two applications were received by the Commission. A summary of the correspondence and the comments from the PPHs is described in the next section of this decision.

Evidentiary hearings began on June 22, 2015 and concluded on July 15, 2015. A total of 18 days of evidentiary hearings were held, and over 400 exhibits were identified and used during the course of these proceedings.[6]

[6] The showing by the Applicants consists of direct testimony, rebuttal testimony, workpapers in support of direct and rebuttal testimony, and other exhibits used during the examination of witnesses. The showing by the other parties consist of direct and rebuttal testimony, and other exhibits used during the examination of witnesses. The other parties who sponsored testimony are: ORA; California Coalition of Utility Employees (CCUE); Environmental Defense Fund (EDF); Federal Executive Agencies (FEA); Joint Minority Parties; Mussey Grade Road Alliance (MGRA); San Diego Consumers Action Network (SDCAN); Southern California Generation

Footnote continued on next page

In response to the scoping ruling, the Commission's Safety and Enforcement Division (SED) prepared a report on the safety aspects of the applications of SDG&E and SoCalGas. The SED report evaluated selected safety and risk program areas that were included in the GRC applications. The SED report was admitted into evidence as Exhibit 23, and the Applicants and other parties were provided the opportunity to respond to SED's report in responsive testimony.

At the conclusion of the evidentiary hearings, the filing of opening and reply briefs were scheduled for August 28, 2015, and September 18, 2015, respectively.

The update testimony, and the comparison exhibits were served on August 17, 2015.

Following the close of the evidentiary hearings, the Applicants began settlement discussions with several of the parties. As a result, the Applicants and some of the parties filed motions and an e-mail request for additional time to file possible motions to adopt the settlements, and for additional time to file the opening and closing briefs. (See Rulings filed on August 20, 2015, and September 8, 2015.)

The September 8, 2015 ruling extended the filing date for the opening briefs from August 28, 2015 to October 12, 2015, and the filing of reply briefs was extended from September 18, 2015 to November 2, 2015. The ruling further stated that "Depending on the contents of the motions to adopt the Joint Settlement, we anticipate that the opening briefs to be filed by October 12, 2015

Coalition (SCGC); TURN; the Utility Consumers' Action Network (UCAN); and Utility Workers Union of America (UWUA).

shall address the non-settled issues only, and that the reply briefs to be filed by November 2, 2015 shall respond only to the parties' opening briefs on the non-settled issues."

On September 11, 2015, three separate motions to adopt settlements were filed. The first motion is the "Joint Motion For Adoption of Settlement Agreements Regarding San Diego Gas & Electric Company's Test Year 2016 General Rate Case, Including Attrition Years 2017 and 2018" (SDG&E Settlement Motion). The second motion is the "Joint Motion For Adoption of Settlement Agreements Regarding Southern California Gas Company's Test Year 2016 General Rate Case, Including Attrition Years 2017 and 2018" (SoCalGas Settlement Motion). The third motion is the "Joint Motion of San Diego Gas & Electric Company, Southern California Gas Company and Office of Ratepayer Advocates For Adoption of Settlement Agreement Regarding the Post-Test Year Period" (PTY Settlement Motion). These three motions are discussed in more detail later in this decision.

Pursuant to Rule 12.2 of the Commission's Rules of Practice and Procedure, seven opening comments were filed on October 12, 2015 to the three settlement motions, and three reply comments were filed on October 27, 2015.

In accordance with the September 8, 2015 ruling, five parties filed opening briefs on October 12, 2015, and five parties filed reply briefs on November 2, 2015. These proceedings were submitted following the filing of the reply briefs on November 2, 2015.

In a May 9, 2016 ruling, TURN's motion to set aside submission was granted for the limited purpose of admitting Exhibit 416 into evidence. These proceedings were again submitted as of May 9, 2016.

Pursuant to Pub. Util. Code § 1701.3(d) and Rule 13.13, oral argument was requested by the Applicants, and held on _________.

To the extent that any outstanding motions or requests have not been addressed in this decision or elsewhere, we deny those outstanding motions or requests. We also confirm all of the oral and written rulings that the assigned Administrative Law Judges (ALJs) have issued in this proceeding.

2. PPHs and Correspondence

PPHs were held in different locations within the service territories of SDG&E and SoCalGas regarding their GRC applications. The PPHs are held to receive comments from the utilities' customers regarding the impact of the applications on them. In addition, a number of letters and e-mails were sent to the Public Advisor's Office of the Commission concerning the two GRC applications.

Many of the comments at the PPHs, and the correspondence that was received, oppose the proposed increases that the Applicants are requesting. They oppose a rate increase because of the state of the economy, and economic circumstances. Some of the speakers at the PPHs, and many of letters and e-mails, point out that a number of the customers of SDG&E and SoCalGas are on fixed incomes and cannot afford any increase in their utility bills. Those on fixed or limited incomes point out that there have only been minimal increases to Social Security, and that salaries have not increased. In addition, some of them state that some customers are faced with the choice of paying their utility bill or purchasing the other necessities of life. Several customers state that with the abundance of lower priced natural gas supplies, that the proposed rate increases are not justified. Other customers question the need for rate increases when the inflation rate has remained low.

Some customers question whether the executives of the utilities and shareholders of the utilities will be the ones who benefit the most from the proposed rate increases as a result of bonuses, other forms of executive compensation, or an increase in the stock price. Others recommend that the utilities should be more fiscally responsible and reduce their operating costs in various areas, including the salaries and benefits of their employees and management. Some of the speakers and correspondence also question the need for additional monies to improve, maintain, and repair the existing infrastructure, and believe that the utilities should have set aside reserves or used the utilities' profits to fund these activities.

Others who spoke at the PPHs support the increases requested by SoCalGas and SDG&E. These include speakers representing first responders, community organizations, chamber of commerce organizations, businesses, and suppliers to the utilities. They state that the utilities are responsive to emergencies and high priority incidents, provide training to first responders, and that the proposed increases are minimal compared to the safety of the utility's system and emergency response times. They also contend that the proposed increase will be used to maintain and upgrade the existing infrastructure in order to ensure safe and reliable service. These upgrades also have an economic ripple effect on local businesses. Those businesses who sell goods and services to the utilities under the supplier diversity programs mention the opportunities to grow their businesses, and to improve their business skills through educational programs.

A number of employees of SoCalGas, who are also customers of SoCalGas, and are represented in this proceeding through the UWUA, voice support for SoCalGas' application. They state that the increases should be used to maintain, improve, and replace existing infrastructure. Due to the knowledge held by the aging SoCalGas workforce concerning the location of SoCalGas facilities and pipelines, these employees support training programs that pass on the knowledge of these experienced workers to the younger workers, and to improve the information contained in the computerized mapping systems. In addition, the proposed increase request of SoCalGas can be used to obtain the tools that workers need in order to effectively perform their work. Some of the employees also state that line extensions to provide new service and to respond to non-emergency calls (including situations where service was turned off because of nonpayment, payment was later made but service has not been restored), can take several days or weeks before a field technician can respond, and that the proposed increase could be used to improve staffing in order to respond more quickly.

Several speakers spoke in favor of SDG&E's electric vehicle proposal, and SDG&E's pole replacement program. Other speakers mention the need to protect and secure the utilities' systems from cyber attacks. Other speakers suggest that the Commission should consider allowing SoCalGas and other utilities to offer a discounted economic development rate in order to attract and retain manufacturing companies in certain communities.

Some customers recommend that SDG&E's current tier pricing structure for electricity should remain in place, and that SDG&E's proposal to increase the rates for the lower tiers, while reducing the rates for the higher tiers, should not be adopted. Customers also stated that the tiered electricity rates should take family size into account in setting the tiers. Some customers contend that the current pricing structure encourages energy conservation. Another SDG&E customer supports the continuing use of net metering in order to allow those who have installed solar units to continue receiving financial benefits in the future.

3. Background of the Applications

SDG&E's service territory covers about 4,100 square miles from southern Orange County to the California-Mexico border. SDG&E operates and maintains an electric and natural gas distribution system that serves about 1.4 million electric customers, and about 845,000 gas customers. SDG&E has approximately 14,821 miles of gas pipelines.

SoCalGas' service territory covers an area of about 20,000 square miles from portions of the central valley down to southern Orange County and Imperial County. SoCalGas operates and maintains a natural gas distribution and transmission system with about 3,990 miles of large and high-pressure pipeline, and about 97,400 miles of gas distribution pipeline that serve about 5.8 million gas customers. The primary function of SoCalGas' distribution network is to receive natural gas from SoCalGas' transmission system and to redeliver the gas at a lower pressure to serve residential and commercial customers. SoCalGas also operates four underground gas storage facilities, which before the Aliso Canyon leakage incident, had a working capacity of about 134 billion cubic feet (Bcf), a combined firm injection capacity of 850 million cubic feet per day (MMcfd), and a combined firm withdrawal capacity of 3195 MMcfd.[7]

The two applications cover TY 2016, with rates effective January 1, 2016, and the PTY periods of 2017 and 2018.

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[7] Aliso Canyon is SoCalGas' largest underground storage field, which had a working capacity of 86.2 Bcf before the shutdown ordered by the Division of Oil, Gas and Geothermal Resources (DOGGR).

SDG&E's GRC application seeks authorization to revise its current base rate revenues to recover its projected costs of using its electric and gas facilities, infrastructure, and other necessary functions, to provide electricity and natural gas services to its customers. Prior to the filing of the settlement, SDG&E requested that the Commission adopt its updated test year 2016 revenue requirement of $1,895,437,000, and that its revenue requirements be reflected in rates beginning January 1, 2016. SDG&E also requested that its PTY mechanism be adopted for the proposed attrition years of 2017 and 2018. In addition, SDG&E requested that the Commission approve its regulatory balancing and memorandum accounts as set forth in its testimony.

ORA reviewed SDG&E's GRC application, and recommended a TY 2016 revenue requirement of $1.710 billion. Other parties also recommend that various adjustments be made to SDG&E's request.

SoCalGas' GRC application seeks authorization to revise its current base rate revenues to recover its projected costs of using its facilities, infrastructure, and other necessary functions, to provide natural gas services to its customers. Prior to the filing of the settlements, SoCalGas requested that the Commission adopt its updated test year 2016 revenue requirement of $2,331,187,000 and that its revenue requirement be reflected in rates beginning January 1, 2016. SoCalGas also requested that its PTY mechanism be adopted for the proposed attrition years of 2017 and 2018. In addition, SoCalGas requested that the Commission approve its regulatory balancing and memorandum accounts as set forth in its testimony.

ORA reviewed SoCalGas' GRC application, and recommended a TY 2016 revenue requirement of $2.145 billion. Other parties also recommended that various adjustments be made to SoCalGas' request.

SDG&E and SoCalGas are related companies owned by the same corporate parent, Sempra Energy (Sempra). Due to their corporate structure, and the businesses that they are in, there are some shared services between the two utilities and their corporate parent.[8]

Shared services are activities performed by functional areas at one utility or at Sempra's corporate center for the benefit of (i) the other utility, (ii) corporate center, and/or (iii) an unregulated affiliate. A shared service provided by SDG&E, SoCalGas, or the corporate center, will be allocated and billed to the entity or entities receiving the service. A utility receiving the shared service will include the costs that were allocated and billed to it.

Non-shared services are activities provided by functional areas at one utility that benefit only the utility performing the activity, the costs of which do not need to be allocated and billed out to other entities. These non-shared services costs may include labor costs and non-labor costs. For services provided to the utility by the corporate center, those costs are treated as non-shared services costs by the utility, consistent with how outside vendor costs are treated.

In the sections below, we first describe the settlement agreements that were entered into. This is followed by an analysis of the settlements and issues affecting SDG&E, and then an analysis of the settlements and issues affecting SoCalGas.

4. Description of the Three Settlement Agreements

After the close of the evidentiary hearings, the following three settlement agreements were entered into and filed with the Commission: the SDG&E

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[8] These shared and non-shared services are reflected in the various pieces of the Applicants' testimony.

Settlement Motion, the SoCalGas Settlement Motion, and the PTY Settlement Motion. A description of each of the settlement agreements is provided below.

4.1. SDG&E Settlement Motion

The SDG&E Settlement Motion was filed jointly by the following: SDG&E; ORA; FEA; EDF; Joint Minority Parties;[9] TURN; UCAN; and SDCAN. The SDG&E Settlement Motion is composed of five settlement agreements that are appended to the SDG&E Settlement Motion as Attachments 1 through 5. We refer to each of the five settlement agreements by their respective Attachment number to the SDG&E Settlement Motion. The SDG&E Settlement Motion requests, among other things, that the Commission grant the motion and adopt all five of the Attachments.

Attachment 1 is labeled as the "Settlement Agreement Regarding SDG&E's Test Year 2016 General Rate Case Revenue Requirement, Including Attrition Years 2017 and 2018."[10] Attachment 1 was entered into by the following parties: SDG&E; ORA; FEA; TURN; UCAN; EDF; Joint Minority Parties; and SDCAN.

Attachment 2 is labeled as "Settlement Agreement Among SDG&E, SoCalGas, and FEA." Attachment 2 was agreed to by SDG&E, SoCalGas, and FEA.

Attachment 3 is labeled as "Settlement Agreement Among EDF, SDG&E and SoCalGas." Attachment 3 was agreed to by SDG&E, SoCalGas, and EDF.

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[9] The Joint Minority Parties refers to the following entities: National Asian American Coalition; the Ecumenical Center for Black Church Studies, the Jesse Miranda Center for Hispanic Leadership; Orange County Interdenominational Alliance; Christ Our Redeemer AME Church; and the Los Angeles Latino Chamber of Commerce.

[10] If we abbreviated the party's name earlier, we use the abbreviation in the title of the document.

Attachment 4 is labeled as "Settlement Agreement Among SDG&E, SoCalGas, and Joint Minority Parties." Attachment 4 was agreed to by SDG&E, SoCalGas, and the Joint Minority Parties.

Attachment 5 is labeled as "Settlement Agreement Among SDG&E, SoCalGas, TURN, And UCAN." Attachment 5 was agreed to by SDG&E, SoCalGas, TURN, and UCAN.

The settlement agreements in Attachments 2, 3, 4, and 5 of the SDG&E Settlement Motion are identical to the settlement agreements in Attachments 2, 3, 4, and 5 of the SoCalGas Settlement Motion.

4.1.1. Description of Attachment 1 Settlement Agreement

The settling parties have agreed in Attachment 1 to the SDG&E Settlement Motion to a combined TY 2016 revenue requirement for SDG&E of $1,810,533,000 ($310,487,000 for gas; and $1,500,046,000 for electric). For the attrition years of 2017 and 2018, the settling parties have agreed to an escalation rate of 3.5% for each year. These settlement numbers are supported in detail by the "Joint Settlement Comparison Exhibit of SDG&E" (SDG&E Settlement Comparison Exhibit), which is dated September 2015, and is appended to the Attachment 1 settlement agreement. The SDG&E Settlement Comparison Exhibit consists of the following four parts:[11]

I. Introduction

II. Exhibit A – Settlement Agreement Terms Between SDG&E and ORA.

[11] When we refer to the SDG&E Settlement Comparison Exhibit in this decision, we use the page numbering shown in the lower right hand corner of that document.

III. Detailed Comparison Analysis, with a separate table of contents and index

IV. Appendices

Appendix A. Settlement Terms Cross Reference
Appendix B. Summary of Earnings Tables

The Introduction to the SDG&E Settlement Comparison Exhibit states that it presents the settlement terms between SDG&E and ORA, and that the format is similar to the Litigation Comparison Exhibit that was served following the completion of the evidentiary hearings. The Introduction goes on to state that "SDG&E and ORA negotiated these settlement terms independently from the Update Testimony served in August 2015, and that Update Testimony does not subsequently alter any of the settlement terms." (SDG&E Settlement Comparison Exhibit at 3.)

"Exhibit A - Settlement Agreement Terms Between SDG&E and ORA" (Exhibit A) to the SDG&E Settlement Comparison Exhibit at pages 5-14 sets forth a breakdown of the agreed upon settlement amounts by functional area. Exhibit A sets forth the agreed upon amounts for the expenses associated with the following functional areas: (1) gas distribution, transmission, engineering and pipeline integrity; (2) electric distribution; (3) electric generation and San Onofre Nuclear Generating Station (SONGS); (4) customer services; (5) information technology (IT); (6) support services; (7) administrative and general; and (8) working cash related issues for SDG&E.

Exhibit A also sets forth the agreed upon amounts for capital expenditures. The agreed upon capital expenditures are for: (1) gas distribution, transmission, engineering and pipeline integrity; (2) electric distribution; (3) electric generation; (4) IT; and (5) support services.

The agreements regarding the working cash issues involve the following: cash balances; revenue lag days; federal income tax lag days; state income tax lag days; and a revenue requirement adjustment of $2.480 million. In addition, the working cash section of Exhibit A sets forth the PTY escalation rates of 3.5% for 2017 and 2018, and also addresses: continuing balancing account treatment for certain programs; the forecasted payroll tax rate; the forecasted service establishment fees; the sales forecast; and continuation of the currently authorized Z-factor mechanism.

The Detailed Comparison Analysis of the SDG&E Settlement Comparison Exhibit (at pages 15-323) provides the references to the exhibits sponsored by various parties, and compares the monetary and policy differences between SDG&E and ORA.

The two appendices to the SDG&E Settlement Comparison Exhibit (at pages 324-348) consist of (1) Appendix A, the Settlement Terms Cross Reference; and (2) Appendix B, the Summary of Earnings Tables.

The Settlement Terms Cross Reference, which is Appendix A to the SDG&E Settlement Comparison Exhibit at pages 325-331, summarizes the monetary differences of SDG&E, ORA, and the agreed upon settlement amounts for the operating and maintenance (O&M) costs and capital costs for the various sub-categories of costs for SDG&E, as well as the agreement on other issues.

The Summary of Earnings Tables, which is Appendix B to the SDG&E Settlement Comparison Exhibit at pages 332-348, sets forth a comparison of the agreed upon revenue requirements by general cost categories, and in further detail by workgroup costs.[12]

The SDG&E Settlement Comparison Exhibit is intended by the settling parties to fulfill the requirement of Rule 12.1 of the Commission's Rules, which states in part:

> When a settlement pertains to a proceeding under a Rate Case Plan or other proceeding in which a comparison exhibit would ordinarily be filed, the motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing.

4.1.2. Description of Attachment 2 Settlement Agreement

Attachment 2 is the settlement agreement entered into by SDG&E, SoCalGas, and the FEA. These three parties have agreed in the Attachment 2 settlement agreement as to how SDG&E's Pension Balancing Account (PBA), and the Post-Retirement Benefits Other Than Pension Balancing Account (PBOPBA), will be treated. The settling parties agree that SDG&E will retain the current balancing account treatment, and that the tariffs will remain unchanged. These three parties further agree that SDG&E's proposal to begin including income tax impacts in those balancing accounts is not being adopted, which reflects the position of FEA.

As part of the terms of the settlement in Attachment 2, FEA agrees to sign and join the settlement agreements that were reached among SDG&E, SoCalGas,

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12 Unless otherwise stated, when we refer to the "summary of earnings table" for SDG&E in this decision, we are referring to the tables which appear in Appendix B to the SDG&E Settlement Comparison Exhibit.

and ORA concerning the TY 2016 revenue requirement and PTY issues in the GRC applications of SDG&E and SoCalGas.

4.1.3. Description of Attachment 3 Settlement Agreement

SDG&E, SoCalGas, and EDF have agreed in Attachment 3 to the following:

1. It is their intent to continue to have active, good faith negotiations on the substantive issues related to compliance with Senate Bill (SB) 1371 in the context of Order Instituting Rulemaking (R. or Rulemaking) 15-01-008, with the goal of working collaboratively towards reaching common understandings, positions, and/or stipulations on as many of the issues as feasible.[13]

2. It is also their intent to continue to work together in good faith to determine a plan of repair for SDG&E's backlog of non-hazardous leaks, as SDG&E expends the funds requested in this GRC, prior to the conclusion of the SB 1371, R.15-01-008.

3. Among the areas of ongoing discussions and negotiations are:

   a. Development of a system of prioritization for the non-hazardous leak repairs performed prior to the completion of the SB 1371 Rulemaking, with the goal of addressing the backlog in a cost effective, environmentally conscious and efficient manner; and

   b. Maintaining the Pipeline and Hazardous Materials Safety Administration (PHMSA) definitions of "leak" and "hazardous" for purposes of implementing SB 1371.

4. The New Environmental Regulatory Balancing Account (NERBA), as proposed in this GRC by SDG&E and SoCalGas,

[13] SB 1371 added Pub. Util. Code Sections 975, 977, and 978. These three code section address the abatement of methane leaks in gas pipeline facilities regulated by the Commission.

should be adopted. That is, as a two-way balancing account, and with the proposed modifications. (See Exhibits 174 and 177.)[14]

5. To the extent costs associated with compliance with SB 1371 exceed the forecasted costs for LDAR during the GRC cycle, as provided by SDG&E and SoCalGas in Exhibits 174, 175, 177, and 178, these parties support, and will seek any additional necessary regulatory authority to clarify that the recovery of those costs is permissible using the adopted NERBA for the duration of the GRC cycle.
6. The GRC should be resolved under its own procedural schedule, and should not remain open to await resolution of issues raised in R.15-01-008.
7. This settlement is not precedent setting and is in effect until the end of the adopted GRC cycle.

The Attachment 3 settlement agreement acknowledges that EDF is signing the settlement agreements that were reached among SDG&E, SoCalGas, and ORA concerning the TY 2016 revenue requirement and PTY issues in the GRC applications of SDG&E and SoCalGas.

4.1.4. Description of Attachment 4 Settlement Agreement

Attachment 4 is the settlement agreement with SDG&E, SoCalGas, and the Joint Minority Parties. They have agreed in Attachment 4 to the following, among other things:

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[14] As described in Exhibits 174 and 177, the Applicants request that the existing NERBA be continued as a two-way balancing account with three changes. The first change is to remove the gas cap and trade related costs from the NERBA on the condition that the Commission authorizes recording these costs pursuant to R.14-03-003. The second change is to include in the NERBA the O&M and capital costs for compliance with the new water quality-related Municipal Separate Storm Sewer System known as the MS4 permit. The third change is to include in the NERBA the costs for Leak Detection and Repair (LDAR).

1. The parties agree that the Chief Executive Officer (CEO) of SDG&E and SoCalGas will meet privately once annually with representatives from the Joint Minority Parties to discuss topics pertaining to supplier diversity, customer programs, work force demographics, and philanthropy.

2. SDG&E and SoCalGas agree to host an annual public forum, wherein representatives from the Joint Minority Parties will be invited to offer input on topics pertaining to supplier diversity, customer programs, environmental issues, and philanthropy.

3. With regard to supplier diversity, SDG&E and SoCalGas agree to modify their annual General Order (GO) 156 Reports to provide information regarding the size of the utilities' diverse suppliers based on annual revenue information currently reported in the Commission's Supplier Clearinghouse database.

4. With regard to supplier diversity, SDG&E and SoCalGas agree to provide informal reports to the Joint Minority Parties, on an annual basis, regarding the utilities' hiring of "returning veterans." These reports will be based on information the utilities will begin collecting from their suppliers upon the execution of the Attachment 4 settlement agreement.

5. With regard to supplier diversity, SDG&E and SoCalGas agree to set aspirational goals of increasing the annual dollar amount spent for Small Contractor Opportunity Realization Effort (SCORE) diverse business enterprise (DBE) participants by 7% each year covered in this GRC period.

6. SCORE provides opportunities for selected new and growing DBEs to demonstrate their ability to work with utilities through low dollar, short term agreements. The criteria for SCORE participants include annual revenue of $5 million or less and 25 or fewer employees, as reported to the Commission's Supplier Clearinghouse.

7. With respect to supplier diversity, SDG&E and SoCalGas will encourage all of its Tier 1 suppliers to participate in an

annual meeting jointly hosted by SDG&E, SoCalGas, and the Joint Minority Parties. Small and medium size DBEs will be invited to attend, with the intention of increasing opportunities for DBEs to connect and contract with larger businesses. No contracts are guaranteed to result from the opportunities provided by these meetings.

8. With respect to the review and selection of auditing firms, SDG&E and SoCalGas agree to continue their efforts to employ diverse firms to conduct accounting reviews and audits not currently conducted by Deloitte and Touche.

9. With respect to the review and selection of auditing firms, SDG&E and SoCalGas agree to host an annual networking meeting with minority certified public accountant firms to discuss potential opportunities.

10. SDG&E and SoCalGas agree to encourage their large law firms (100+ attorneys) to provide pro bono work.

11. SDG&E and SoCalGas agree to host an annual networking meeting with their law firms and the Joint Minority Parties to discuss opportunities for pro-bono work.

12. With regard to small business development, SDG&E and SoCalGas agree to continue to work with the Joint Minority Parties to discuss ways to increase the number of small businesses in the Commission's Utility Supplier Diversity Program.

13. For small business development, SDG&E and SoCalGas will commit to investing at least a combined amount of $650,000 annually in technical assistance and capacity building programs to small minority owned businesses. Each company will seek to leverage this funding with matching funds from other corporations, governments, and private foundations. Each company will commit to maintain or exceed its current efforts in the areas of technical assistance and capacity building for small minority owned businesses. SDG&E and SoCalGas define "technical assistance" as primarily educational efforts, and "capacity building" as

efforts of community-based business organizations to attract and retain members that can do business with utilities.

14. As part of the terms of the settlement in Attachment 4, the Joint Minority Parties agree to sign and join the settlement agreements that were reached among SDG&E, SoCalGas, and ORA concerning the TY 2016 revenue requirement and PTY issues in the GRC applications of SDG&E and SoCalGas.

4.1.5. Description of Attachment 5 Settlement Agreement

Attachment 5 reflects the agreement of SDG&E, SoCalGas, TURN, and UCAN to settle all of the issues raised and litigated in the TY 2016 GRCs of SDG&E and SoCalGas, with the exception of the Income Tax – Repair Allowance issue. TURN and UCAN also agree to join, as signatories, the settlement agreements that were reached among SDG&E, SoCalGas, and ORA concerning the TY 2016 revenue requirement and PTY issues in the GRC applications of SDG&E and SoCalGas.

SDG&E, SoCalGas, TURN, and UCAN agree to the following:

1. For the TY 2016 revenue requirement and PTY for 2017 and 2018, the four parties agree that the settlement terms reached among SDG&E, SoCalGas, and ORA address the full range of issues related to the revenue requirement for TY 2016, and the 2017 and 2018 attrition years. TURN and UCAN have reviewed the proposed overall revenue requirement for 2016, 2017, and 2018, and agree that the proposed amount for each of these years is reasonable in light of the record, including the testimony sponsored by TURN and UCAN. Therefore, the four parties agree that the overall revenue requirements set forth in Attachment 1 of the SDG&E Settlement Motion, and Attachment 1 of the SoCalGas Settlement Motion, should be deemed incorporated into Attachment 5 to both settlement motions.

2. That each utility will continue to maintain separate two-way balancing accounts for their Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) expenditures. The advice letter process for recovery of any TIMP or DIMP undercollections will be limited to undercollection amounts up to 35% of the 2016 GRC cycle total revenue requirement for that program and will require a Tier 3 advice letter. Any amounts above the 35% will be subject to a separate application procedure.

3. All issues associated with the income tax – repair allowance will be litigated separately from the settlement in Attachment 5, based on the existing evidentiary record and briefs to be submitted by interested parties.

4. For SDG&E only, the four parties agree that:

   a. SDG&E's Service Establishment Charge will be set at $5.85 for all customers.

   b. SDG&E may file a separate application to seek closure of any currently existing branch offices during the 2016 GRC cycle.

   c. Rates for SDG&E's customers will be adjusted on January 1, 2016, to reflect roll-off of the GRC Memorandum Account balances associated with SDG&E's 2012 GRC Phase 1, irrespective of the timing of a final decision in this GRC.

   d. SDG&E's rate recovery of any costs associated with the Manzanita wind project and transmission interconnection for that project is limited to the amount received for the return on cash working capital for Preliminary Surveys and Investigations in this 2016 GRC cycle. SDG&E agrees not to seek rate recovery of any costs associated with the project in any future Commission or Federal Energy Regulatory Commission (FERC) rate case.

   e. Prior to the filing of its next GRC application, SDG&E will perform and present a detailed and appropriate study of distributed generation (DG) impacts on circuit peak loads, based on actual data concerning the impact of DG on specific circuits. At a minimum, the study will seek to aggregate circuits with similar load profiles to better estimate the potential of DG to reduce circuit peaks and distribution expenditures in future GRCs.

4.2. SoCalGas Settlement Motion

The SoCalGas Settlement Motion was filed jointly by the following: SoCalGas; ORA; UWUA; FEA; EDF; Joint Minority Parties; TURN; and UCAN. The SoCalGas Settlement Motion is composed of five settlement agreements that are appended to the SoCalGas Settlement Motion as Attachments 1 through 5. We refer to each of the five settlement agreements by their respective Attachment number to the SoCalGas Settlement Motion.

Attachment 1 to the SoCalGas Settlement Motion is labeled as the "Settlement Agreement Regarding SoCalGas' Test Year 2016 General Rate Case Revenue Requirement, Including Attrition Years 2017 and 2018." Attachment 1 was agreed to by the following parties: SoCalGas; ORA; UWUA; FEA; TURN; and UCAN.

Attachments 2, 3, 4, and 5 are identical to the same attachments that we described for SDG&E. Various portions of these four Attachments may contain provisions that apply solely to SoCalGas, or to SDG&E.

4.2.1. Description of Attachment 1 Settlement Agreement

The settling parties have agreed in the Attachment 1 settlement agreement to a TY 2016 revenue requirement for SoCalGas of $2,219,426,000. For the attrition years of 2017 and 2018, the settling parties have agreed to an escalation rate of 3.5% for each year. These settlement numbers are supported in detail by the "Joint Settlement Comparison Exhibit of SoCalGas" (SoCalGas Settlement Comparison Exhibit) which is dated September 2015, and appended to

Attachment 1 of the SoCalGas Settlement Motion. The SoCalGas Settlement Comparison Exhibit consists of the following four parts:[15]

I. Introduction

I. Exhibit B – Settlement Agreement Terms Between SoCalGas and ORA.

II. Detailed Comparison Analysis, with a separate table of contents and index

III. Appendices

Appendix A. Settlement Terms Cross Reference
Appendix B. Summary of Earnings Tables

The Introduction to the SoCalGas Settlement Comparison Exhibit states that it presents the settlement terms between SoCalGas and ORA, and that the format is similar to the Litigation Comparison Exhibit that was served following the completion of the evidentiary hearings. The Introduction goes on to state that "SoCalGas and ORA negotiated these settlement terms independently from the Update Testimony served in August 2015, and that Update Testimony does not subsequently alter any of the settlement terms." (SoCalGas Settlement Comparison Exhibit at 3.)

"Exhibit B - Settlement Agreement Terms Between SoCalGas and ORA" (Exhibit B) to the SoCalGas Settlement Comparison Exhibit sets forth a breakdown of the agreed upon settlement amounts by functional area. The agreed upon settlement amounts are for the following functional areas: (1) gas distribution; (2) gas transmission, underground storage, gas engineering, and

[15] When we refer to the SoCalGas Settlement Comparison Exhibit in this decision, we use the page numbering listed in the lower right hand corner of that document.

pipeline integrity; (3) customer services; (4) IT; (5) support services; and (6) administrative and general.

Exhibit B also sets forth the agreed upon amounts for the capital expenditures and working cash related issues. The agreed upon capital expenditures are for: (1) gas distribution; (2) underground storage; (3) gas transmission and engineering; (4) pipeline integrity; (5) fleet services & facility operations; and (6) IT capital expenditures.

The agreements regarding working cash issues involve the following: cash balances; revenue lag days; federal income tax lag days; state income tax lag days; and a revenue requirement adjustment of $3.072 million.

In addition, Exhibit B sets forth the PTY escalation rates for 2017 and 2018, and also addresses: continuing balancing account treatment for certain programs; the payroll tax rate; the uncollectible rate; miscellaneous revenues; and continuation of the currently authorized Z-factor mechanism.

The Detailed Comparison Analysis of the SoCalGas Settlement Comparison Exhibit (at pages 14-275) provides the references to the exhibits sponsored by various parties, and compares the monetary and policy differences between SoCalGas and ORA.

The two appendices to the SoCalGas Settlement Comparison Exhibit consist of (1) Appendix A, the Settlement Terms Cross Reference; and (2) Appendix B, the Summary of Earnings Tables.

The Settlement Terms Cross Reference, which is Appendix A at pages 277-281 of the SoCalGas Settlement Comparison Exhibit, summarizes the monetary differences of SoCalGas, ORA, and the agreed upon settlement amounts for the O&M costs and capital costs for the various sub-categories of costs for SoCalGas.

The Summary of Earnings Tables, which is Appendix B at 283 of the SoCalGas Settlement Comparison Exhibit, sets forth a comparison of the agreed upon revenue requirements by general cost categories, and in further detail by workgroup costs.

The SoCalGas Settlement Comparison Exhibit is intended by the settling parties to meet the comparison exhibit requirement of Rule 12.1 of the Commission's Rules.

4.2.2. Description of Attachment 2 Settlement Agreement

I. Introduction

I. Exhibit B – Settlement Agreement Terms Between SoCalGas and ORA.

II. Detailed Comparison Analysis, with a separate table of contents and index

III. Appendices

Appendix A. Settlement Terms Cross Reference
Appendix B. Summary of Earnings Tables

The Introduction to the SoCalGas Settlement Comparison Exhibit states that it presents the settlement terms between SoCalGas and ORA, and that the format is similar to the Litigation Comparison Exhibit that was served following the completion of the evidentiary hearings. The Introduction goes on to state that "SoCalGas and ORA negotiated these settlement terms independently from the Update Testimony served in August 2015, and that Update Testimony does not subsequently alter any of the settlement terms." (SoCalGas Settlement Comparison Exhibit at 3.)

"Exhibit B - Settlement Agreement Terms Between SoCalGas and ORA" (Exhibit B) to the SoCalGas Settlement Comparison Exhibit sets forth a breakdown of the agreed upon settlement amounts by functional area. The agreed upon settlement amounts are for the following functional areas: (1) gas distribution; (2) gas transmission, underground storage, gas engineering, and pipeline integrity; (3) customer services; (4) IT; (5) support services; and (6) administrative and general.

Exhibit B also sets forth the agreed upon amounts for the capital expenditures and working cash related issues. The agreed upon capital expenditures are for: (1) gas distribution; (2) underground storage; (3) gas transmission and engineering; (4) pipeline integrity; (5) fleet services & facility operations; and (6) IT capital expenditures.

The agreements regarding working cash issues involve the following: cash balances; revenue lag days; federal income tax lag days; state income tax lag days; and a revenue requirement adjustment of $3.072 million.

In addition, Exhibit B sets forth the PTY escalation rates for 2017 and 2018, and also addresses: continuing balancing account treatment for certain programs; the payroll tax rate; the uncollectible rate; miscellaneous revenues; and continuation of the currently authorized Z-factor mechanism.

The Detailed Comparison Analysis of the SoCalGas Settlement Comparison Exhibit (at pages 14-275) provides the references to the exhibits sponsored by various parties, and compares the monetary and policy differences between SoCalGas and ORA.

The two appendices to the SoCalGas Settlement Comparison Exhibit consist of (1) Appendix A, the Settlement Terms Cross Reference; and (2) Appendix B, the Summary of Earnings Tables.

The Settlement Terms Cross Reference, which is Appendix A at 277-281 of the SoCalGas Settlement Comparison Exhibit, summarizes the monetary differences of SoCalGas, ORA, and the agreed upon settlement amounts for the O&M costs and capital costs for the various sub-categories of costs for SoCalGas.

The Summary of Earnings Tables, which is Appendix B at 283 of the SoCalGas Settlement Comparison Exhibit, sets forth a comparison of the agreed upon revenue requirements by general cost categories, and in further detail by workgroup costs.

The SoCalGas Settlement Comparison Exhibit is intended by the settling parties to meet the comparison exhibit requirement of Rule 12.1 of the Commission's Rules.

4.2.3. Description of Attachment 3 Settlement Agreement

Attachment 3 is the settlement agreement entered into by SoCalGas, SDG&E, and EDF. This Attachment 3 is identical to the Attachment 3 Settlement Agreement in the SDG&E Settlement Motion, as described earlier.

4.2.4. Description of Attachment 4 Settlement Agreement

Attachment 4 is the settlement agreement of SoCalGas, SDG&E, and the Joint Minority Parties. This Attachment 4 is identical to the Attachment 4 Settlement Agreement in the SDG&E Settlement Motion, as described earlier.

4.2.5. Description of Attachment 5 Settlement Agreement

Attachment 5 is the agreement of SoCalGas, SDG&E, TURN, and UCAN to settle all of the issues raised and litigated in the TY 2016 GRCs of SDG&E and SoCalGas, with the exception of the Income Tax – Repair Allowance issue. This Attachment 5 is identical to the Attachment 5 settlement agreement in SDG&E's Settlement Motion, as described earlier.

4.3. PTY Settlement Motion

The third settlement motion is labeled as the "Joint Motion of SDG&E, SoCalGas and ORA for Adoption of Settlement Agreement Regarding The Post-Test Year Period" (PTY Settlement Motion). Attached to the PTY Settlement Motion is the "Settlement Agreement Regarding the Post-Test Year Period" (PTY Settlement Agreement). The PTY Settlement Motion was agreed to, and filed by SDG&E, SoCalGas, and ORA.

The PTY Settlement Agreement agrees to add an additional attrition year, 2019, to the Applicants' current three year GRC cycle of a 2016 test year and the attrition years of 2017 and 2018. The PTY Settlement Agreement also agrees to apply an escalation factor of 4.3% to the 2019 attrition year. The PTY Settlement Agreement is contingent upon the two following conditions:

- Commission adoption of the settlement agreements in the SDG&E Settlement Motion, and in the SoCalGas Settlement Motion; and
- Commission adoption of four-year GRC cycles for the major California investor-owned utilities (consisting of Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), SDG&E, and SoCalGas), to avoid overlapping GRC test years. SDG&E, SoCalGas, and ORA agree to jointly request such relief through a petition for modification of the Commission's Rate Case Plan (RCP) in R.13-11-006, or by another appropriate procedural mechanism.

Thus, if the Commission agrees to modify the GRC rate cycle to four years, each of the four major utilities would be on four year rate cycles in the future.

However, the PTY Settlement Agreement provides that if both of the above conditions are not satisfied (i.e., the Commission, in its final decision in these proceedings does not adopt either or both of the Attachment settlement agreements in the SDG&E Settlement Motion and the SoCalGas Settlement

Motion, and/or, the Commission does not grant the relief request in R.13-11-006 prior to the current schedule under which SDG&E and SoCalGas must file their next GRC applications), then the PTY Settlement Agreement will be deemed null and void. In such an event, SDG&E and SoCalGas will proceed with the filing of their next GRC applications in September 2017 as a test year 2019 GRC.

The PTY Settlement Agreement also addresses "ORA's practice of conducting its audit in GRCs, which the Commission may elect to use to satisfy the requirements of [Pub. Util. Code] Section 314.5, in connection with SDG&E's and SoCalGas' GRC proceedings." (PTY Settlement Agreement at 3-4.) The PTY Settlement Agreement provides that if the 2019 attrition year is adopted, that ORA will conduct an audit of the 2016 recorded costs, and ORA will deliver the completed audit to the Commission's Executive Director, and serve it on the parties to these proceedings. The "Applicants agree to provide ORA with any information it needs to conduct a general audit of the Test Year of each utility." (PTY Settlement Agreement at 4.)

SDG&E, SoCalGas, and ORA agree that the PTY Settlement Agreement complies with the Commission's Rules for the adoption of a settlement for the following reasons:

- The settling parties have vigorously negotiated toward a PTY period and escalation rate that reflects compromises on both sides. In doing so, the settling parties specifically considered the positive and negative aspects of a three- and four-year GRC cycle, and the potential that the settled 2019 escalation rate may be too high or too low, depending on future economic outcomes. The settled 2019 escalation reflects the settling parties' best judgment as to the totality of factors and risks.
- The settling parties used reasoned judgment to arrive at the settled 2019 escalation rate and agree that, as in any forecasting exercise, there is a range of reasonable outcomes. The settling

parties also agree that different methodologies can produce results within this range and that no single methodology will produce the sole reasonable result in every instance.

- The four-year GRC cycle and escalation factor reflected in the PTY settlement provides an overall 2019 revenue requirement that the settling parties believe will allow SDG&E and SoCalGas to operate and manage their systems safely, reliably, and efficiently, while keeping customer rates reasonable.
- The PTY Settlement Agreement intends to minimize the potential for delays in GRC proceedings and manage the increase in the settling parties' workload due to new regulatory requirements set forth in D.14-12-025 integrating the Safety Model Assessment Proceeding (S-MAP) and the Risk Assessment Mitigation Phase (RAMP) into the Commission's RCP. The settling parties note that even without these new requirements, SDG&E's and SoCalGas' test year 2012 GRC decision took 876 calendar days between application and final decision, which is 492 days longer than the 384-day period set forth in the RCP. The public interest is served by minimizing regulatory delays, in part to avoid impacting the timing of work and capital projects, many of which are for critical safety and reliability efforts. Minimizing delays also creates greater rate stability, to the benefit of customers.
- The settling parties believe, and herein represent, that no term of the PTY Settlement Agreement contravenes statutory provisions or prior Commission decisions. The Commission has previously adopted rate case terms longer than the traditional three-year cycle. Although the Commission recently affirmed a three-year GRC cycle in D.14-12-025, the Commission recognized that implementing these new procedures would place additional burdens on litigating parties, and that circumstances may warrant altering the schedule as needed.

5. Analysis Approach

5.1. Overview of Analysis

In the sections which follow, we first provide an overview of how we have analyzed the revenue requirement requests of SDG&E and SoCalGas, and interim safety and accounting reports. This is then followed by an analysis of SDG&E's GRC application and the related settlements and other issues affecting SDG&E. This is then followed by an analysis of SoCalGas' GRC applications and the related settlements and other issues affecting SoCalGas.

This decision generally follows how the summary of earnings tables for the Applicants are structured, as shown in the Attachment 1 Settlement Agreements to the SDG&E and SoCalGas Settlement Motions. The summary of earnings table sets forth all of the components of the revenue requirement. The revenue requirement consists of the total O&M costs, and the capital-related costs, that are necessary to support the Applicants' respective rate base. To arrive at the overall revenue requirement, each of the pertinent line items on the summary of earnings table is discussed in the context of the testimony and the settlements on those topics.

Appendix A of this decision contains the adopted summary of earnings tables for SDG&E and SoCalGas, while Appendix B of this decision contains the adjustments that we adopt to the revenue requirements of SDG&E and SoCalGas. The summary of earnings tables shown in Appendix A reflects all of the costs or methodologies we have found to be reasonable as inputs into the Results of Operation (RO) model. The RO model is the model used by the Applicants to generate the revenue requirement amount that is needed to allow SDG&E and SoCalGas to earn the authorized rate of return on their investments.

In each section, we describe the background of the particular costs that are being addressed. This is followed by a summary of the parties' positions, the applicable portions of the settlement agreements, and then a discussion of the costs and other issues.

Since the evidence and arguments in this proceeding are voluminous, and the settlement agreements have agreed on most of the issues, we focus our attention on the major points of contention, and did not try to summarize each party's positions on each individual issue. However, that does not mean that we have overlooked individual issues raised by the parties. We have reviewed all of the exhibits in this proceeding, as well as the arguments made by the parties in their briefs, and considered all of the arguments and issues that parties have raised in deciding what costs should be adopted. This review and evaluation process included the following:

- Reviewed all of the exhibits and briefs pertaining to each section of this decision. The exhibits reviewed include the direct and rebuttal testimony, the applicable workpapers, and the other exhibits used during the examination of the witnesses.
- Reviewed and evaluated the positions of the parties on the issues raised, and compared and evaluated each parties' forecasted costs and methodologies to the agreements reached in the SDG&E Settlement Motion, and in the SoCalGas Settlement Motion.
- Considered the state of the economy and the economic outlook as described in the parties' exhibits, and compared the forecasts of the parties and the agreed upon settlement amounts in light of the economic outlook.
- After going through this review and evaluation process, we then decide on what TY 2016 cost or outcome is reasonable, and whether it should be adopted.

The above review and evaluation process results in the revenue requirements that are appropriate for SDG&E and SoCalGas to provide safe and reliable service at just and reasonable rates, as required by Pub. Util. Code § 451.

5.2. Safety and Risk Mitigation and Accountability Reporting

The Commission is committed to safe utility operations, and we expect the utilities to make safety a foundational priority in everything they do. The Applicants have reflected their consciousness and attention to safety and risk mitigation throughout their testimony. When evaluating the revenue requirements requested by SDG&E and SoCalGas, the Commission has placed an emphasis on programs and activities that enhance the safety and reliability of the Applicants' natural gas and electric power infrastructure and operations.

After the 2010 San Bruno pipeline explosion and fire, the Commission moved towards the use of a risk based approach to assess the different kinds of risk inherent in operating a utility, and how those potential risks affect the costs of operating a utility. In D.14-12-025, the Commission revised the rate case plan to adopt a risk based approach to ratemaking. In that decision, the Commission adopted procedures that will result in additional transparency and participation on how the safety risks for the energy utilities are prioritized by the energy utilities and the Commission, and to provide accountability for how these safety risks are managed, mitigated and minimized.[16]

These new procedures include the following:

- Safety Model Assessment Proceeding (S-MAP) to review/evaluate utility risk models;
- Risk Assessment Mitigation Phase (RAMP) to investigate how utilities are applying their risk model results into the Safety investments they will seek in the GRC; and

[16] The implementation of some of these procedures is being examined in the consolidated proceedings of Application (A.) 15-05-002, A.15-05-003, A.15-05-004, and A.15-05-005.

- Accountability reports that will review whether the Investor-Owned Utilities' (IOUs') actual expenditures aligned with what had been approved, and what Safety impact has been measured.

The GRC applications of SDG&E and SoCalGas were filed prior to the issuance of D.14-12-025. Many of the details about these new processes are being determined in the ongoing S-MAP proceedings, and in the RAMP proceedings which will follow.

As mentioned earlier, SED prepared a safety report (Exhibit 23) which evaluated selected safety and risk program areas of the GRC applications of SDG&E and SoCalGas. The SED report contained recommendations relating to the safety and risk program areas evaluated by SED. The SED report recommends that the utilities continue to evolve their risk management programs. The SED report also recognizes that effective risk management is dependent on having accurate data, and to evaluate the effectiveness of risk management will require appropriate metrics.

In 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, the Applicants will be required to provide a limited version of the accountability reports described in D.14-12-015.[17]

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[17] The two Accountability Reports described in D.14-12-025 are: a Risk Spending Accountability Report, in which the utility compares its GRC projected spending for approved risk mitigation projects with the actual spending on those projects, and explains any discrepancies; and a Risk Mitigation Accountability Report, in which the utility compares its GRC projections of the benefits and costs of the risk mitigation programs adopted in the GRC with the actual benefits and costs, and explains any discrepancies.

SDG&E and SoCal Gas shall provide a Spending Accountability Report one year after today's GRC decision is issued. This report shall compare TY 2016 authorized spending to actual 2014 and 2015 spending on a limited set of risk mitigation projects. The report shall also propose a methodology 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 such as those currently being determined in the S-MAP and RAMP proceedings.

These limited set of risk mitigation projects that SDG&E and SoCalGas are to report on are the high level programs and the top ranked operational risks described in the SED Staff Report (Exhibit 23), as follows:

> 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. For example, specific Fire Risk Management (FiRM) projects identified in testimony and in the SED report include, replace live front equipment; weather instrumentation; Powerworkz; C1215 Fire Mitigation; FiRM Phases 1, 2 & 3,[18] C441 Pole Loadings; Aerial marking; CNF Brakes; and SF6 switch replacement.[19]

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[18] The SED Report concluded that SDG&E did not provide a very specific plan for the latter phases of the FiRM program (which primarily addresses pole replacement, reconductoring and pole loading assessments), and recommended the following: "SED is unable to ascertain the specific locations that SDG&E expects to prioritize under FiRM's phasing sequence. A more complete evaluation of this program -- whether conducted in this GRC, or as part of future accountability reports associated with the Commission's S-MAP/RAMP process – will require a more detailed work plan from SDG&E, with maps and more thorough enunciation of why specific locales were prioritized over others." (Exhibit 23 at 44.)

[19] See Exhibit 23, Table 1 at 29.

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.[20]

Additionally, the report should cover the specific component replacement/maintenance programs that were identified in CCUE's direct testimony[21] 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 DIMP.[22] 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, TIMP, and the Storage Integrity Management Program (SIMP).

A second report shall be due two years from the issuance of this GRC decision, which is to include actual 2016 spending.

SDG&E and SoCalGas are directed to work with SED and Energy Division staff to determine the exact format and content of these reports. The reports shall

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[20] The utility acknowledged it had improved data in these areas in testimony. (Exhibit 134 at 24.)

[21] See Exhibit 337 at 21-34.

[22] The SED report did not detail mitigation projects associated with these aspects, but the utility's testimony and workpapers provide a detailed compendium.

be filed in these GRC proceedings, and served on the service list of these proceedings, and the S-MAP proceedings referenced earlier.

Subsequent reporting requirements beyond what is being required above will be supplanted by the direction provided in D.14-12-025, a decision in either or both the S-MAP and RAMP proceedings, or in the next GRC proceedings of the Applicants.

6. SDG&E A.14-11-003

6.1. Introduction

As updated in its update testimony, SDG&E requests that the Commission authorize a total revenue requirement of $1,895,437,000 ($324,188,000 for gas operations, and $1,571,249,0000 for electric operations). In the combined summary of earnings table for SDG&E, the settling parties agree to a total revenue requirement of $1,810,533,000 ($310,487,000 for gas operations, and $1,500,046,000 for electric operations).[23]

The cost components which make up the revenue requirement for SDG&E's electric operations are shown in SDG&E's Electric Summary of Earnings table. The cost components which make up the revenue requirement for SDG&E's gas operations are shown in SDG&E's Gas Summary of Earnings table. The Combined Summary of Earnings table, which appears in the SDG&E Settlement Comparison Exhibit at 333, reflects the revenue requirement for the combined operations of SDG&E.

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[23] The combined summary of earnings table for SDG&E can be found at 333 of the SDG&E Settlement Comparison Exhibit. The SDG&E Settlement Comparison Exhibit is appended to Attachment 1 of the SDG&E Settlement Motion.

In the sections which follow, we first discuss the cost components that make up the O&M costs, followed by the other components which are added to the O&M costs to arrive at the total revenue requirement.

6.2. Distribution

Line 4 of SDG&E's summary of earnings tables shows the O&M costs for distribution-related activities.

6.2.1. O&M Distribution Costs for Electric Operations

According to SDG&E, its electric distribution system includes "287 distribution substations, 1,016 distribution circuits, 230,197 poles, 10,290 miles of underground system, 6,569 miles of overhead systems, and various other pieces of distribution equipment." (Exhibit 70 at 2.) The electric distribution facilities are located across various types of terrain such as bay and coastal areas, inland valleys, mountain communities, and desert communities. Additionally, there are approximately 450,000 trees in the proximity of SDG&E's overhead lines.

SDG&E's electric distribution system is approximately 60% underground. According to SDG&E, an underground system is significantly more expensive to install, has a shorter equipment life expectancy, requires more time to troubleshoot problems, and takes longer to repair.

This section addresses SDG&E's forecast of electric distribution O&M expenses for TY 2016. These O&M costs are for activities related to the operation, maintenance, supervision, and engineering of its electric distribution system. These activities include the following:

- Routine maintenance and new construction;
- Inspection and associated repair;
- Dispatch and electric system control;

- Project planning and design;
- Skill training of the workforce;
- Development of standards, strategic planning, and distribution reliability functions;
- Management of contract construction forces;
- Public affairs communication and liaison activities with local, state and federal agencies; and
- Development, implementation, operation and maintenance of distribution system related IT systems.

SDG&E's original forecast of Electric Distribution O&M expenses was $140.119 million, which is an increase of $32.637 million over its 2013 adjusted-recorded expenses of $107.482 million.[24] In its update testimony, SDG&E adjusted its O&M distribution forecast to $134.150 million.

The amount agreed to in the SDG&E Settlement Motion for electric distribution O&M costs is $126.760 million.

SDG&E's electric distribution O&M activities are divided into 26 primary cost categories as shown in Exhibit 70.[25] The four major cost categories are electric regional operations, electric distribution operations, vegetation

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[24] The $140.119 million amount shown in Exhibit 70 varies slightly from the $136.528 million shown in Table KN-2 of SDG&E's summary of earnings testimony in Exhibit 219.

[25] As described in Exhibit 70, the cost categories of exempt materials, small tools, and department overhead pool, are not directly charged to O&M or capital expenditures. Instead, the appropriate charges are allocated to the appropriate gas and electric O&M accounts and capital budgets as indirect charges. For that reason, these three cost categories are not addressed in this electric distribution cost section.

management, and construction services.[26] We discuss each of these categories below.

6.2.1.1. Electrical Regional Operations

Electric Regional Operations (ERO) is composed of electric distribution crews located in six districts, and two satellite operating centers. The primary function of the crews include the inspection and maintenance of SDG&E's electric distribution system, restoration of service due to outages, repair of service problems, and addressing other customer issues. SDG&E originally requested $36.859 million[27] for TY 2016 which is $5.110 million more than its 2013 adjusted-recorded expenses of $31.749 million. SDG&E utilized a base year plus incremental increases methodology in calculating its forecast in order to capture future increases in fire preparedness, elevated wind conditions and outage patrolling during high fire risk, and also to capture additional staffing and increases in non-labor costs.

The cost drivers for SDG&E's forecasted increase in costs are primarily due to: (1) public and employee safety, system maintenance and reliability; (2) safety and regulatory compliance; (3) fire risk mitigation;[28] (4) workforce development; (5) system growth; and (6) improving operational efficiencies.

ORA recommended $33.055 million for the O&M costs associated with ERO. ORA took issue with SDG&E's failure to distinguish between additional

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[26] These four cost categories account for about 71% of SDG&E's electric distribution O&M forecast.

[27] SDG&E modified its request for ERO in its update testimony to $35.449 million.

[28] SDG&E's testimony notes that with drought conditions, red flag warnings are likely to be higher than average.

work and ongoing work which ORA contends resulted in a double-counting of expenses.

The FEA recommended $31.157 million for the ERO O&M costs based on declining costs since 2012.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to the amount of $35.449 million for ERO TY2016 costs.

Based on SDG&E's testimony regarding the additional costs it expects to incur, and the drought conditions which are likely lead to increased activities relating to fire risk mitigation and safety, the agreed upon amount of $35.449 million is reasonable and should be adopted. This agreed upon amount is $1.410 million less than SDG&E's original request.

6.2.1.2. Troubleshooting

This cost category is for engineering and system troubleshooting to ensure safe and reliable service to customers. SDG&E utilizes electric troubleshooters who have the necessary skills to restore electric service during emergencies and unplanned outages. They also perform other tasks such as substation and field switching, and substation and routine safety patrols. The troubleshooting cost category also provides engineering, planning, administrative and supervisory support. For TY 2016, SDG&E is requesting $7.965 million. SDG&E's forecasted increase is due to increased costs in fire risk mitigation, system growth and enhanced training for this workforce.

ORA recommended $7.650 million for the troubleshooting O&M costs. ORA stated that SDG&E did not provide a workload analysis to justify the additional troubleshooters in SDG&E's forecast.

CCUE recommended that SDG&E be required to hire more employees due to the drop in the number of troubleshooters, and SDG&E's measured decline in electric reliability.

SDG&E claims that ORA's forecast is based on unusually low 2014 figures, as compared to historical cost averages. SDG&E agrees with CCUE's proposal that it hire new employees as needed, but disagrees that its electric reliability is declining. To the contrary, SDG&E contends it has a high national reliability record.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to SDG&E's original forecast of $7.965 million.

In this instance, SDG&E's forecast methodology better reflects the TY 2016 forecasted costs, as opposed to ORA's reliance on 2014 costs. The troubleshooting costs are partly dependent on elevated wind and red flag warning conditions, which makes it appropriate to use historical costs rather than a single point in time. Based on the testimony of the parties, and comparing that to the agreed upon settlement amount of $7.965 for the troubleshooting cost category, that amount is reasonable and should be adopted.

With respect to the issue raised by CCUE, we agree with SDG&E that it can better determine workforce needs and can adjust the number of troubleshooters that it hires based on actual need.

6.2.1.3. Skills & Compliance Training

The Skills & Compliance Training group is responsible for the development and training of the ERO workforce, which is comprised of electric field personnel, non-electrical support personnel and first line supervision. Subject matter experts borrowed from the field comprise about 80% of the instructors. As described in Exhibit 70, these training programs consist of the following: electric linemen development; compliance training required by various regulations; equipment operations and commercial drivers' training; ancillary training; system and process initiatives; and specialized task-specific training programs. According to SDG&E, these training programs result in a "workforce with the required skills to safely and reliably maintain and operate the electric distribution system, in compliance with GOs 95, 128, 165 and SDG&E standards, work methods, and operating procedures." (Exhibit 70 at 19.)

SDG&E is requesting $5.087 million for TY 2016, which is an increase over its 2013 adjusted-recorded expenses of $3.660 million. SDG&E utilized base year plus incremental increases to calculate its forecast. The cost drivers for the increase are due to SDG&E's focus on workforce development, use of simulators and demonstration boards for training, aging infrastructure and equipment, and safety, regulatory and environmental compliance.

ORA recommended no increase from SDG&E's 2013 expense of $3.660 million. ORA contends that the development and training of the ERO force is part of SDG&E's ongoing operations, and SDG&E has failed to show how its forecasted incremental work is different from ongoing work.

SDG&E contends that ORA's position fails to recognize the increase in its workforce, the aging workforce, and the need for additional training to develop its ERO workforce.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agreed to the amount of $4.0 million for the O&M costs associated with Skills and Compliance Training.

Based on the testimony of SDG&E and ORA, and the need to train the number of new employees as the current aging workforce retires, the agreed upon settlement amount of $4.0 million for the O&M costs associated with Skills and Compliance Training is reasonable and should be adopted.

6.2.1.4. Project Management

Project Management activities relate to the preparation of construction orders. The Project Management personnel provide the design and engineering needed to develop the construction orders for the additions or modifications to the electric distribution system. These construction orders can be for individual customers, or for large distribution systems that serve subdivisions, commercial centers, and high rise buildings.

For TY 2016, SDG&E is requesting $1.368 million which is higher than its 2013 adjusted-recorded expenses of $0.482 million. The cost drivers for SDG&E's forecasted increase include filling five new planner positions lost through attrition and retirement, training for new planners, additional support staff, and returning personnel from special assignments.

ORA recommended that the Project Management O&M costs be set at $0.528 million. ORA contends that in the 2012 GRC, SDG&E requested a similar level of funding and used similar reasons to justify its forecast. Although SDG&E was authorized $1.100 million in the 2012 GRC, ORA points out that SDG&E only spent $0.409 million for Project Management.

SDG&E contends that the 2012 GRC decision was not issued until 2013, which made it difficult to conduct the requested training, and re-scheduled those activities for this GRC cycle. SDG&E also points out that 2014 spending was unusually low compared to other years.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to the amount of $0.800 million.

With the exception of 2011 when SDG&E spent $0.797 million, the actual costs for this workgroup since 2009 did not exceed $0.482. After examining the parties' testimonies and arguments, as well as the historical costs, the settlement amount of $0.800 million for Project Management O&M costs is reasonable and should be adopted.

6.2.1.5. Service Order Team

The Service Order Team is responsible for planning, overseeing, and managing additions and modifications to SDG&E's electric distribution system. Although most costs involved are capital costs, there are O&M costs for support of construction operations and acting as customer representative for these projects. SDG&E is requesting $0.883 million for TY 2016, which is higher than its 2013 adjusted-recorded expense of $0.846 million.

ORA recommended $0.685 million for the O&M costs associated with the Service Order Team. ORA used SDG&E's 2014 expenses, instead of SDG&E's use of 2013 as a base plus incremental increases.

SDG&E contends that the spending in 2014 was unusually low, and does not reflect normal spending.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agreed to the amount of $0.700 million.

Based on the testimony of SDG&E and ORA, and the incremental increases that SDG&E proposed by SDG&E, the agreed upon amount of $0.700 million is reasonable and should be adopted.

6.2.1.6. Regional Public Affairs

The Regional Public Affairs group supports electric and gas distribution operations through its work with regional and local governments on issues regarding proposed regulations, permits, and emergency preparedness response.

This workgroup also provides education and information to governmental officials and stakeholders. For TY 2016, SDG&E is requesting $1.687 million, which is the same amount of its 2013 adjusted-recorded expenses.

Prior to entering into the settlement, SDCAN took the position that SDG&E failed to provide detailed justification for its forecasted amount, and that the forecasted amount did not reflect the historical costs of this workgroup. SDCAN contends that some of these costs were in support of lobbying activities and enhancing SDG&E's corporate image. SDCAN recommended that SDG&E's requested amount be reduced by $1.004 million, which results in an amount of $0.683 million for this cost category.

SDG&E asserts that it provided detailed testimony, which is based on its historical costs.

In the SDG&E Settlement Comparison Exhibit, the parties agreed to SDG&E's forecast of $1.687 million.

The amount of $1.687 million that was agreed to by the settling parties for the Regional Public Affairs O&M costs is reasonable as it is supported by SDG&E's historical spending. Accordingly, the agreed upon amount of $1.687 million for Regional Public Affairs O&M costs should be adopted.

6.2.1.7. Grid Operations

The Grid Operations workgroup is responsible for the overall installation, testing, calibration, and maintenance for all Supervisory, Control & Data Acquisition (SCADA) equipment that interfaces with the transmission energy management systems and the distribution management systems. For TY 2016, SDG&E is requesting $0.348 million, which is higher than its 2013 adjusted-recorded expenses of $0.148 million. SDG&E used a three-year average in making its forecast.

ORA recommended in its testimony that the amount of $0.226 million be adopted since the cost for these activities has been declining since 2009.

In the SDG&E Settlement Comparison Exhibit, the settling parties agreed to the amount of $0.148 million.

The amount proposed in the settlement is equal to SDG&E's base year expenses, which reflects a decline in expenses for this cost category. Accordingly, we find that the agreed upon amount of $0.148 for Grid Operations O&M costs to be reasonable and should be adopted.

6.2.1.8. Substation Construction & Maintenance

The Substation Construction and Maintenance unit oversees and maintains 140 distribution substations. It also ensures compliance with SDG&E's maintenance programs, the regulatory programs of the Commission as well as other agencies, and with health and safety programs. SDG&E is requesting $6.912 million for TY 2016, which is $1.016 million higher than its 2013 adjusted-recorded expenses of $5.896 million. SDG&E's forecasted increase in costs is due to fire risk mitigation, regulatory and environmental compliance, and training.

ORA contends that SDG&E did not justify why an increase of over the 2014 recorded costs is needed. ORA recommended $5.622 million be adopted for this cost category.

SDG&E claims it adequately described the upward costs in its testimony.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agreed to SDG&E's revised forecast of $6.710 million, which is slightly lower than SDG&E's original request.

We reviewed the testimony of SDG&E and ORA and determined that there is sufficient justification in the record for the settling parties to agree on

$6.710 million for the Substation Construction and Maintenance costs. Accordingly, this amount is reasonable and should be adopted.

6.2.1.9. System Protection

System Protection is comprised of the Relay Technician group which maintains protective relays and control systems within SDG&E's substations, and the SCADA group, which works on installing distribution voltage regulators, capacitors, distribution reclosers, weather stations, and distribution of equipment and switchgear controlled by SCADA. For TY 2016, SDG&E is requesting $1.711 million, which is higher than its 2013 adjusted-recorded expense of $1.545 million. SDG&E's forecasted increase is due to incremental costs relating to fire protection, regulatory and environmental compliance, system growth, and the adoption of new technology to SDG&E's aging infrastructure.

None of the parties objected to SDG&E's forecast, or to the agreed upon amount of $1.711 million contained in the SDG&E Settlement Comparison Exhibit at 7.

We have reviewed and considered the testimony presented by SDG&E and ORA, and that the agreed upon amount of $1.711 million for the System Protection workgroup is reasonable and should be adopted.

6.2.1.10. Electric Distribution Operations

The Electric Distribution operations workgroup is responsible for the delivery of power to SDG&E's 3.4 million consumers through approximately 1.4 electric smart meters. For TY 2016, SDG&E is requesting $15.315 million, which is $4.377 million higher than the 2013 adjusted-recorded expenses of $10.938 million. SDG&E used a 3-year linear methodology to calculate its forecast. Cost drivers for SDG&E's forecasted increase is due to grid modernization, workforce development, additional costs to maintain the system, and fire risk mitigation.

Both ORA and FEA recommended $11.377 million for these O&M costs. ORA and FEA both utilized a three-year average, which they believe is more appropriate to justify the up and down fluctuations that have occurred since 2009.

SDG&E contends that the 2014 spending was unusually low, which does not reflect historical costs.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to a compromise forecast of $14 million for the O&M costs associated with Electric Distribution Operations.

Based on our review of the testimony of SDG&E, ORA, and the FEA, and the recorded historical costs, the agreed upon settlement amount of $14 million for Electric Distribution Operations is reasonable and should be adopted.

6.2.1.11. Distribution Operations/Enterprise Geographic Information Standards

Enterprise Geographic Information Standards is responsible for providing real-time mapping of all assets in the fields related to electric distribution, substation and telecommunication. SDG&E states that accurate and timely maps "are essential to safety and reliability for operational groups, including the switching center, who direct field personnel that operate equipment when restoring service or when constructing new capital projects." (Ex. 70 at 43.) SDG&E recommends O&M costs of $2.647 million for this cost category.

ORA contends that the historical costs do not support SDG&E's requested amount and that costs declined in 2014. ORA recommends $1.996 million for this cost category.

SDG&E claims that spending in 2014 was unusually low.

In the SDG&E Settlement Comparison Exhibit at 7, the parties have agreed to ORA's recommended amount of $1.996 million.

Based on the testimony of SDG&E and ORA, and the amount agreed to in Attachment 1 settlement agreement of the SDG&E Settlement Motion, the agreed upon O&M amount of $1.996 million is reasonable and should be adopted.

6.2.1.12. Kearny Operations Services

The Kearny Operations Services unit includes the following workgroups: (1) compliance and analysis; (2) tool repair; (3) apparatus; (4) transformer repair and high voltage test; and (5) protective equipment testing laboratory. The work activities of these different workgroups are described in Exhibit 70.

For TY 2016, SDG&E is requesting $2.239 million, which is higher than its 2013 adjusted-recorded expenses of $1.838 million. SDG&E utilized a base year plus incremental increases for its forecast. SDG&E contends that higher costs are necessary due to increased operational costs, and to maintain compliance with sulfur hexafluoride emissions regulations.

ORA recommended $1.736 million for these O&M costs. ORA states that it used a four-year average and added $0.080 million for compliance with regulations. ORA also notes that SDG&E's 2014 expenses for this cost category was a decrease from the 2013 levels.

SDG&E contends that the 2014 spending was unusually low, which resulted in a lower forecast as determined by ORA.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed on a compromise forecast of $1.900 million.

The agreed upon settlement amount of $1.900 million for the Kearny Operations Services is reasonable based on the historical spending that took place as explained in the testimony of ORA and SDG&E. This amount should be adopted.

6.2.1.13. Construction Services

The Construction Services unit is comprised of following four main groups: Construction Services Construction Management; Construction Services Contracting; Aviation Services; and Fire Coordination and Prevention.

The Construction Services Construction Management group provides construction management and oversight of all construction performed by contractors on the electric distribution system. According to SDG&E, this construction management and oversight is performed to ensure that the work is built in accordance with SDG&E's Design and Safety Standards and GO 95 and GO 128.

The Construction Services Contracting group is responsible for many of the administrative tasks associated with construction services and construction management.

The Aviation Services group provides the oversight for construction related activities that involve the use of helicopter and fixed wing aircraft.

The Fire Coordination and Prevention group works with SDG&E's engineering, operations, and construction units to include fire safety and fire preventative measures and procedures into the activities that these other units perform. The Fire Coordination and Prevention group also coordinates the fire response with SDG&E's operational activities, and oversees the contract fire prevention and suppression services that may be needed. This group also assists with fire safety training to employees and to first responders.

For TY 2016, SDGE is requesting $18.865 million, which is $13.639 million higher than 2013 adjusted-recorded expenses of $5.226 million. SDG&E utilized a five-year average in determining its forecast. The cost drivers include: increased construction as a result of the improving economy; construction work to improve reliability and safety due to an aging distribution system; and fire risk mitigation has led to increased costs.

ORA contends that SDG&E did not adequately justify about $12.2 million in incremental activities that it plans to conduct because SDG&E did not provide a list of the specific activities to be conducted or a breakdown of the costs. ORA recommends that $11.667 million be adopted for this cost activity.

The FEA recommends $11.692 million, and provided similar objections to SDG&E's requested amount.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed on a compromise forecast of $16.00 million.

Although SDG&E is requested $18.865 million for this cost category, SDG&E's recorded expenses for these activities have not exceeded $7.486 million since 2009.[29] However, SDG&E provided testimony on its need for incremental activities, which are due in part to fire risk mitigation projects. Based on the testimony of SDG&E, ORA, and FEA, the agreed upon amount of $16 million for Construction Services is reasonable, and should be adopted.

6.2.1.14. Vegetation Management (Tree Trimming)

SDG&E's Vegetation Management activities involve the inspection and maintenance of approximately 450,000 trees that have the potential to encroach within the minimum compliance distance between vegetation and power lines. These O&M activities include tree trimming, tree removal, and other related

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[29] See Exhibit 331 at 33.

vegetation management expenses. These activities are undertaken to mitigate fire and safety concerns, and to comply with various code sections and regulations.

For TY 2016, SDG&E is requesting $24.559 million, which is higher than the 2013 adjusted-recorded expenses of $23.104 million. The increase in costs is due to higher projected costs for tree trimming and removal, increased inspections due to drought conditions, and increased costs for regulatory and environmental compliance. SDG&E utilized a three-year historical average method, plus an incremental adjustment for costs associated with its PowerWorkz vegetation management system.

SDG&E's expenses for this program currently utilize a one-way balancing account. For this GRC cycle, SDG&E is requesting a two-way balancing account. SDG&E contends that a two-way balancing account will allow SDG&E to manage and mitigate safety and reliability risks due to drought and fire as circumstances arise.

The methodology used by ORA and FEA included the 2014 expenses, but did not add the incremental O&M expenses associated with SDG&E's vegetation management system. ORA and FEA both recommend an amount of $23.858 million for the O&M costs associated with vegetation management.

ORA and FEA also recommend that SDG&E's request for a two-way balancing account be denied. ORA and FEA contend that a two-way balancing account will allow SDG&E to spend without restriction, and that a one-way balancing account will result in less variability as to costs and encourage cost efficiency. UCAN also objects to SDG&E's request for a two-way balancing account for the same reasons that ORA and FEA have provided.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to SDG&E's forecast of $24.559 million for the O&M costs associated with vegetation management activities, and the one-way balancing account.

Based on the testimony of SDG&E, ORA, and FEA, the agreed upon amount of $24.559 million is reasonable given the scope of the vegetation management program, the need for the vegetation information management system, and the activities needed to mitigate the fire risks and to comply with applicable regulations. Accordingly, the amount of $24.559 million should be adopted for the O&M costs associated with the Vegetation Management program.

With regard to the treatment of the Vegetation Management costs, the settling parties agreement to continue the one-way balancing account treatment of these costs is reasonable and should be adopted. The one-way balancing account encourages SDG&E to perform the necessary activities related to tree trimming, and at the same time minimize costs for such activities.

6.2.1.15. Vegetation Management (Pole Brushing)

Pole brushing activities involve the clearing of flammable brush and vegetation from SDG&E distribution poles pursuant to Public Resources Code Section 4292. These activities involve clearing vegetation around the poles, and applying herbicide when applicable. There are currently 86,000 distribution structures that are inspected annually. Of these 86,000 structures, there are 34,000 poles that require follow-up maintenance work and semi-annual brush clearing. In addition, many of SDG&E's poles require multiple visits during the year to ensure compliance.

For TY 2016, SDG&E is requesting $4.292 million, which is higher than its 2013 adjusted-recorded expenses of $3.572 million.

None of the parties to these proceedings object to SDG&E's forecast of the O&M costs for pole brushing.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agreed to the amount of $4.292 million for Vegetation Management – Pole Brushing.

We have reviewed and considered the testimony presented by SDG&E and ORA regarding the pole brushing O&M costs. Based on that testimony, the $4.292 million agreed upon for these costs is reasonable, and should be adopted.

6.2.1.16. Compliance & Asset Management

The Compliance and Asset Management workgroups focus on ensuring SDG&E's compliance with internal and external regulations, policies and procedures related to the operation and maintenance of its electric distribution system.

SDG&E is requesting $2.702 million for TY 2016, which is higher than its 2013 adjusted-recorded expense of $2.458 million. The forecasted increase is due to additional resources needed for compliance with GO 165, which revised the time frame for conducting patrol and inspections, and other new regulations.

None of the parties to these proceeding objected to SDG&E's forecast.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agree to the amount of $2.702 million for the Compliance and Asset Management O&M costs.

We have reviewed and considered the testimony presented by SDG&E and ORA. No one has objected to SDG&E's forecasted amount, and the settling parties have agreed to $2.702 million for the Compliance and Asset Management O&M costs. Based on those considerations, this amount is reasonable and should be adopted.

6.2.1.17. Distribution Engineering

The distribution engineering activities consist of electric distribution standards, and service standards and customer generation. The electric distribution standards work group is responsible for maintaining and developing overhead and underground construction standards to ensure safe and reliable service throughout the electric distribution system.

The service standards workgroup develops and maintains the standards that apply to gas and electric metering and service equipment. The customer generation workgroup is responsible for processing all customer applications for solar and wind generation, and small distributed generation installations.

SDG&E is requesting $1.909 million for these cost categories, which is higher than its 2013 adjusted-recorded expenses of $1.319 million. The forecasted increase in costs is due to the impact of new technology such as plug-in electric vehicles, the increase in the volume of net energy metering, workforce development, and regulatory and environmental compliance.

ORA contends that SDG&E failed to explain how the increase in net energy metering volume results in higher costs. ORA recommends the amount of $1.397 million for the distribution engineering O&M costs.

SDG&E contends that net energy metering increased by 42% in 2014, and such projects will continue to increase. According to SDG&E, this increase will require additional labor to process these requests in a timely manner.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed on a compromise forecast of $1.500 million for Distribution Engineering.

Based on the testimony of SDG&E and ORA, the agreed upon settlement amount of $1.500 million is reasonable in light of the increase in net energy metering volumes. The amount of $1.500 million should be adopted for the O&M costs associated with distribution engineering.

6.2.1.18. Technology Innovation & Development

This workgroup is responsible for promoting the applied and industrial sciences relevant to the advancement of SDG&E's power system electrical, electronic, communication, and control infrastructure. The integrated test facility, which is part of this workgroup, supports the demonstration and testing of the hardware, software, and processes for these technologies.

SDG&E is requesting $0.822 million, which is higher than its adjusted-recorded expenses of $0.327 million. The cost drivers for TY 2016 include additional costs as a result of implementing new technology.

ORA contends that SDG&E's forecasted amount is overstated for the reasons specified in Exhibit 331. ORA recommends that the amount of $0.207 million be adopted for this workgroup.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agree to a compromise amount of $0.400 million.

Based on the testimony of SDG&E and ORA, and the 2014 recorded expenses, the agreed upon amount $0.422 million for the O&M costs associated with Technology Innovation and Development is reasonable and should be adopted.

6.2.1.19. Reliability & Capacity Analysis

This unit provides technical support services related to the O&M of the electric distribution system. As discussed in Exhibit 70, the two main workgroups which provide these services are the technical analysis workgroup, and the distribution planning workgroup.

The technical analysis workgroup is composed of the following three groups: reliability engineering, fire mitigation, and power quality.

The reliability engineering group is responsible for the tracking and reporting of the electric reliability indices in accordance with D.08-07-046 and D.96-09-045. The four key reliability performance indicators are the following: System Average Interruption Duration Index (SAIDI), which is used to measure the duration of outages; System Average Interruption Duration Index Exceeding Threshold, which is used to measure SAIDI exceeding a threshold of 150 minutes; System Average Interruption Frequency Index (SAIFI), which is used to measure the frequency of outages; and Estimated Restoration Time, which is used to measure the accuracy of restoration times for customers within one hour of actual restoration. The reliability engineering group also provides support for programs that target maintaining reliability.

The fire mitigation group leads the Reliability Improvements for Rural Areas Team. One of the responsibilities of the Rural Areas Team is to oversee the evaluation and implementation of various fire hardening activities so as to minimize fire-related risks in rural areas that are in fire threat zones, and highest risk fire areas.

The distribution planning workgroup engages in activities related to the engineering and design of capital projects that support the capacity expansion of the electric distribution system. This workgroup also provides administrative and technical support for the O&M of the electric distribution system.

For TY 2016, SDG&E is requesting $0.618 million, which is higher than its 2013 adjusted-recorded expenses of $0.538 million. The incremental costs are due to software upgrades, and additional costs for regulatory and environmental compliance.

ORA contends that the costs for reliability and capacity analysis have been declining since 2011, and recommend that the amount of $0.502 million be adopted.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed to SDG&E's forecasted amount of $0.618 million.

Based on the testimony of SDG&E and ORA, and the incremental increases due to advances in technology, and the need to improve SDG&E's aging infrastructure, the agreed upon settlement amount of $0.618 million is reasonable, and should be adopted.

6.2.1.20. Electric Reliability Performance Measures

SDG&E has proposed that the Commission use the same electricity reliability performance measures for this GRC that were approved in D.14-09-005. D.14-09-005 was issued in response to a joint petition for modification of D.13-05-010 that SDG&E and CCUE filed. These four reliability indices are SAIDI, SAIFI, Worst Circuit SAIDI, and Worst Circuit SAIFI.

ORA does not object to SDG&E's proposal for the electric reliability performance measures.

The SDG&E Settlement Comparison Exhibit does not reach any agreement on the electric reliability performance measures. Based on the agreement of SDG&E and CCUE that led to the issuance of D.14-09-005, we will continue the use of these four reliability indices for SDG&E's TY 2016 GRC cycle.

6.2.1.21. Information Management Support

This workgroup is responsible for providing the business analytics associated with the maintenance and advancement of geographic information system (GIS) technology to support SDG&E's needs. In addition, this workgroup is responsible for supporting the graphical work design tools.

SDG&E is requesting $0.376 million, which is an increase over its 2013 adjusted-recorded expenses of $0.261 million. SDG&E attributes the increase in costs to new technology.

ORA contends that the additional employees that SDG&E plans to add are already embedded in historical costs. For that reason, ORA recommends $0.140 million for this cost category.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties have agreed on a compromise forecast of $0.200 million for information management support for electric distribution.

Based on the testimony of SDG&E and ORA, and the historical costs that have been incurred, the agreed upon settlement amount of $0.200 million is reasonable and should be adopted.

6.2.1.22. Major Projects

Major Projects is responsible for managing the distribution and substation projects from inception to project conclusion.

SDG&E is requesting $0.147 million, which is higher than its 2013 adjusted-recorded expense of $0.078 million. SDG&E contends that the incremental change is due to the need for additional training in certain areas.

None of the parties have objected to SDG&E's forecast of these O&M costs. In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agree to the amount of $0.147 million.

We have reviewed and considered the testimony presented by SDG&E and ORA. Based on that testimony, the agreed upon amount of $0.147 million is reasonable, and should be adopted for the O&M costs for the major projects cost category.

6.2.1.23. Technology Utilization

The technology utilization workgroup oversees the utilization of technology for SDG&E's electric system. According to SDG&E, this technology is being incorporated into its aging electric system to make the electric grid more reliable, and to operate it more safely and efficiently. The technology utilization workgroup is also an operational response to the growing use of large-scale renewables, plug in electric vehicles, and rooftop solar.

For TY 2016, SDG&E is requesting $1.948 million, which is higher than its 2013 adjusted-recorded expense of $1.287 million. SDG&E contends that the increase in these costs is due to the need for additional workforce development, and to provide the necessary preventative maintenance for these technology upgrades.

ORA takes issue with SDG&E's use of a five-year linear forecast, which ORA contends creates an artificially high base year. ORA also contends that costs have been declining since 2012. ORA recommends $1.243 million for the technology utilization O&M costs.

In the SDG&E Settlement Comparison Exhibit at 7, the parties have agreed to a compromise forecast of $1.500 million.

Based on the testimony of SDG&E and ORA, and the decline in recent costs for this cost category, the agreement upon amount of $1.500 million for the O&M costs associated with technology utilization is reasonable, and should be adopted.

6.2.1.24. Administrative & Management

The administrative and management workgroup supports the budgeting and financial reporting system for electric distribution.

SDG&E is requesting $0.324 million for TY 2016, which is an increase over its 2013 adjusted-recorded expenses of $0.209 million. SDG&E's increase in costs is due to the additional resources needed for regulatory compliance and for its financial reporting tools.

None of the parties objected to SDG&E's forecast.

In the SDG&E Settlement Comparison Exhibit at 7, the settling parties agreed to a forecast of $0.324 million for administrative and management costs.

We have reviewed and considered the testimony presented by SDG&E and ORA. The agreed upon amount of $0.324 million is reasonable as it is supported by SDG&E's testimony. Accordingly, the cost of $0.324 million should be adopted as the O&M costs for the administrative and management workgroup.

6.2.1.25. Officer

The officer workgroup represents the non-labor costs of one vice president and one administrative assistant that support officer activities for electric distribution.

SDG&E's TY 2016 forecast is $0.476 million which is slightly less than its 2013 adjusted-recorded expenses of $0.518 million.

None of the parties have objected to SDG&E's forecast for these officer costs.

The settling parties have agreed in the SDG&E Settlement Comparison Exhibit at 7 to the amount of $0.476 million.

We have reviewed and considered the testimony presented by SDG&E and ORA. The agreed upon settlement amount of $0.476 million is reasonable in light of the testimony, and should be adopted as the O&M costs for the officer workgroup.

6.2.1.26. Summary of Electric Distribution O&M Costs

A summation of the 23 cost categories discussed above results in electric distribution O&M costs of $126.760 million. For the reasons stated above, the amount of $126.760 million should be adopted as the TY 2016 forecast for electric distribution O&M costs.

6.2.2. Distribution Capital Expenditures for Electric Operations

This section addresses SDG&E's capital projects associated with electric distribution. SDG&E is requesting the Commission to adopt the following capital expenditures: 2014 - $443.612 million; 2015 - $486.399 million; 2016 - $474.033 million.

Electric distribution capital projects include such things as plant investments in electric meters, distribution substations, replacing/reinforcing poles, and underground cables. These types of investments are made to distribute electricity, to improve distribution system capacity and reliability (including safety and aging infrastructure), and to transform transmission voltage to a lower voltage for distribution. These capital projects are intended to maintain the delivery of safe and reliable service to SDG&E's customers.

The electric distribution capital costs are divided into 11 primary sections. For ease of reference, and to mirror ORA's analysis in its testimony, we divide the capital costs into Electric Distribution Capital I, and Electric Distribution Capital II.

6.2.2.1. Electric Distribution Capital I

This first group, which we refer to collectively as Electric Distribution Capital I, is comprised of the following five sections: Capacity/Expansion; Franchise; New Business; Reliability/Improvements; and Safety and Risk

Management. SDG&E's total forecast for this first group of capital projects is as follows: 2014 - $259.068 million; 2015 - $287.317 million; 2016 - $287.817 million.

In the SDG&E Settlement Comparison Exhibit at 8, the settling parties stipulate to the following totals for the sections comprising Electric Distribution Capital I: ORA's forecast of $145.552 million for 2014; a forecast of $280.772 million for 2015, and a forecast of $296.428 million for 2016.

6.2.2.1.1. Capacity/Expansion

Capacity/Expansion projects are those which are required for capacity and substation additions, and include facilities necessary to serve system growth. SDG&E's electric distribution system must be constructed to meet peak load for its customers. For capital projects under this section, SDG&E is requesting the following: 2014 - $50.655 million; 2015 - $31.282 million; 2016 - $14.241 million.

As described in SDG&E's Exhibit 134, and in ORA's Exhibit 374, there are a variety of Capacity/Expansion projects that are forecasted for 2014 to 2016, including the following: installation of field shunt capacitors on distribution circuits; reactive small capital projects under $500,000 to address primary distribution system overload and voltage related issues; various work activities at different substation locations; various work activities on different distribution circuits; capacitor upgrades at different substations; and adding additional capacity on the distribution system in heavily loaded areas.

For the 2014 estimate of capital expenditures, ORA included the 2014 adjusted-recorded data. Of the 27 projects under the category of Capacity/Expansion, ORA points out that SDG&E spent more than it had forecasted in 2014 on three projects. ORA also took into consideration the updated completion dates for 20 of these projects and revised the estimated costs based on the updated dates.

Based on ORA's adjustments, ORA recommends the following capital expenditures for Capacity/Expansion: 2014 - $24.912 million; 2015 - $31.324 million; 2016 - $27.052 million.

TURN provided testimony in Exhibit 408 stating that SDG&E does not provide value for the effects of solar distributed generation when it forecasts its distribution Capacity/Expansion capital expenditures. As described in Exhibit 408, TURN recommends a disallowance of 10% to the Mira Sorrento substation project, and a total disallowance of the Salt Creek substation project, and the new C917 circuit project at Chicarita. TURN's recommended forecast is lower than SDG&E's by $10.561 million.

In SDG&E's rebuttal testimony in Exhibit 136, SDG&E does not disagree with TURN's contention that solar distributed generation will play an important role in future distribution capacity plans. However, SDG&E contends that solar distributed generation is not at a penetration level that can offset the need for additional capacity, or relieve SDG&E of its duty to provide safe and reliable electricity to its customers.

In the SDG&E Settlement Comparison Exhibit at 8, the settling parties have agreed to ORA's forecasts of $24.912 million for 2014, and $31.324 million for 2015, and to SDG&E's forecast of $14.241 million for 2016, for the Capacity/Expansion category of capital projects.

Based on the testimony of the parties, and the agreed upon amounts for the Capacity/Expansion capital expenditures, the following agreed upon amounts are reasonable and should be adopted: 2014 - $24.912 million; 2015 - $31.324 million for 2015; 2016 - $14.241 million. These amounts are reasonable because the 2014 amount reflects the actual recorded expenses, and the 2015 amount reflects the updated changes to the project completion dates.

6.2.2.1.2. Franchise

The second category of capital projects under Electric Distribution Capital I is Franchise. These Franchise projects cover the conversion of overhead distribution systems to underground systems, or relocations due to improvements by governmental agencies. SDG&E is required to perform this undergrounding work pursuant to some of its franchise agreements.

For these Franchise projects, SDG&E is requesting the following: 2014 - $41.764 million; 2015 - $41.764 million; 2016 - $41.764 million.

ORA does not disagree with the proposed Franchise projects, but notes that there has been a downward trend in expenditures under this category. ORA also notes that SDG&E spent considerably less than it had forecasted for its 2014 adjusted-recorded expenditure. ORA recommends the following for the Franchise projects: 2014 - $29.918 million; 2015 - $29.918 million; 2016 - $29.918 million.

SDG&E contends that the Franchise work originates by the various jurisdictions, and not by SDG&E. SDG&E contends that the dip in Franchise project spending in 2014, does not mean that SDG&E will experience the same level of spending in the subsequent year.

In the SDG&E Settlement Comparison Exhibit at 8, the settling parties agreed to ORA's forecast of Franchise projects of $29.918 million for 2014, and to SDG&E's forecasts of Franchise projects of $41.764 million for both 2015 and 2016.

Based on the testimony of SDG&E and ORA, and the agreed upon Franchise project amounts in Attachment 1 of the SDG&E Settlement Motion, it is reasonable to adopt the following amounts for the capital expenditures for Franchise projects: 2014 - $29.918 million; 2015 - $41.764 million;

2016 - $41.764 million. These agreed upon amounts are reasonable because it reflects the actual recorded costs for 2014, and the agreed upon amounts for 2015 and 2016 reflect that spending for Franchise projects are likely to increase in 2015 and 2016.

6.2.2.1.3. New Business

The third category of capital projects under Electric Distribution Capital I is New Business. These New Business projects are the direct result of requests from customers. These New Business projects can include the following: new services; upgraded services; new distribution systems for commercial and residential developments; system modifications to accommodate new customer load; customer requested relocations; rearrangements or removals; and conversion of overhead lines to underground.

For these New Business capital projects, SDG&E is requesting the following: 2014 - $58.592 million; 2015 - $70.653 million; and 2016 - $81.962 million.

For its forecast of New Business capital expenditures, ORA incorporated the 2014 adjusted-recorded expenses, and proposed reductions for 2014 and 2015. ORA recommends the following: 2014 - $33.638 million; 2015 - $50.071 million; and 2016 - $$60.480 million. ORA contends that SDG&E's forecast method, which is based on construction units, results in an unreliable forecast that is much higher.

UCAN contends that many of SDG&E's forecasts for capital projects are driven in part by the growth in new customers and overall sales. In Exhibit 347, UCAN recommends that SDG&E's residential electric customer forecast use the February 2015 housing starts forecast developed by IHS Global Insight, instead of the IHS Global Insight forecast of February 2014 for construction starts.

UCAN contends that the construction boom that was anticipated in the February 2014 forecast did not materialize, which resulted in the number of housing starts being too high. UCAN contends that the 2015 IHS Global Insight forecast is more reliable than the 2014 forecast. UCAN points out that the use of the updated forecast has a direct impact on the New Business capital expenditures. UCAN recommends the following amounts for the New Business capital expenditures: 2014 - $51.724 million; 2015 - $56.197 million; and 2016 - $71.757 million. UCAN's recommended amounts are lower than SDG&E's amounts by $31.5 million over the three year period.

In Exhibit 136, SDG&E provided an explanation of why its forecast method using construction units is more appropriate than using housing starts. SDG&E contends that the construction unit forecast is a more appropriate method because it is based on the forecasted number of permits. Such a forecast minimizes lag because it is closer in time in time to the work that is being planned for, and fits better with the timing of budgets.

In the SDG&E Settlement Comparison Exhibit at 8, the settling parties stipulated to ORA's forecast of $33.638 million for 2014, a compromise forecast of $67.000 million for 2015, and a compromise forecast of $70.000 million for 2016.

Based on the testimony of SDG&E, ORA, and UCAN, and the agreements reached in Attachment 1 of the SDG&E Settlement Motion concerning the New Business Projects, the agreed upon amounts are reasonable and should be adopted. The amounts are reasonable because it reflects the actual recorded 2014 expenses, and the agreed upon amounts for 2015 and 2016 reflect a compromise between the methodologies used by SDG&E, and the methodologies advocated for by ORA and others. Accordingly, the following amounts for New Business capital expenditures should be adopted: 2014 - $33.638 million; 2015 - $67.000 million for 2015; and 2016 - $70.000 million.

6.2.2.1.4. Reliability/Improvements

The fourth category of costs under Electric Distribution Capital I are projects for Reliability/Improvements. These are projects to improve or maintain the reliability of SDG&E's aging electric distribution system. As set forth in Exhibit 134, SDG&E proposes 20 capital projects under the Reliability/Improvements section. SDG&E is requesting $81.848 million for 2014, $102.934 million for 2015, and $74.427 million for 2016.

The proposed projects include the following: (1) small changes and improvements to electrical distribution substation facilities; (2) projects to reinforce overhead and underground electric distribution system infrastructure; (3) replacement of underground cable; reconstruction of existing overhead and underground distribution facilities as necessary to restore electric service due to system interruptions; (4) rebuild of various substations; (5) purchase of additional emergency transformer and switchgear; (6) removal of the 4 kilovolt legacy substations from service; install new or upgrade existing security systems at 59 substations; (7) installation of equipment to improve SDG&E's information and control capabilities for distribution systems; (8) installation of advanced energy storage on distribution circuits that have a high concentration of photovoltaic systems; (9) rebuild of three sewage pump stations; (10) install condition-based maintenance monitoring equipment to monitor critical distribution substation assets; (11) install new microgrid systems or enhance existing microgrids for service reliability; (12) install equipment for distribution circuit reliability; (13) install new operating and communications infrastructure to monitor substation power quality; and (14) replacement of obsolete substation equipment to improve safety and reliability.

ORA obtained updated completion dates for the twenty projects included in this section. ORA's recommended amounts reflect the 2014 adjusted-recorded expenses, and adjustment of capital spending based on the updated list of completion dates. ORA recommends the following: 2014 - $28.678 million; 2015 - $85.893 million; 2016 - $104.099 million.

CCUE recommends an additional $280.80 million for reliability projects focused on wood poles, underground cable, capacitors, and underground switches. CCUE also recommends that the Commission establish a two-way balancing account to ensure that SDG&E spends required amounts for reliability improvements.

The Joint Minority Parties recommend that SDG&E explore the use of new technology such as the Tesla battery. In Exhibit 136, SDG&E notes that it already installed two separate Tesla battery systems, and is continuing to evaluate energy storage alternatives.

Due to an inadvertent error in a data response to ORA about in-service dates, ORA made adjustments to capital spending. Since these projects are ongoing, instead of specific in-service dates, SDG&E contends that its forecasts of capital spending are still correct and should be adopted over ORA's recommendations.

With respect to CCUE's proposal, SDG&E states that the current forecast for projects already allows it to maintain its high standard of reliability for its customer. SDG&E opposes CCUE's recommendation for a two-way balancing account because "it reduces SDG&E's ability to reprioritize and adjust funds to meet our customer's needs." (Exhibit 136 at 32.)

In the SDG&E Settlement Comparison Exhibit at 8, the settling parties have stipulated to the following for the capital projects for Reliability/Improvements: for 2014, to ORA's forecast of $28.678 million, plus $9.160 million, for a total of $37.838 million in Reliability/Improvements; for 2015, to a compromise forecast of $100.000 million; and for 2016, to a compromise forecast of $95.000 million.

The parties did not object to SDG&E's proposed capital projects for the Reliability/Improvements category, but did request revisions to the forecasted amounts based on scheduling. CCUE requested additions to SDG&E's capital projects.

With respect to CCUE's recommendations for additional spending, and the establishment of a two-way balancing account, those issues were not resolved by the SDG&E Settlement Motion since CCUE was not a signatory to the SDG&E Settlement Motion, or to any of the attached settlement agreements. Based on the testimony that SDG&E and CCUE presented, the additional spending advocated for by CCUE is not supported by the evidence. CCUE has not demonstrated that its request for additional spending is needed to improve or maintain the reliability of SDG&E's electric distribution system. Instead, SDG&E's explanations of its anticipated projects for the Reliability/Improvements category will enable SDG&E to continue providing safe and reliable electric service to its customers.

We also find that the establishment of a two-way balancing account is not needed at this time as it would diminish SDG&E's ability to prioritize or allocate expenses based on what is needed.

With respect to the Joint Minority Parties' recommendation about the use of Tesla batteries, we note that the Joint Minority Parties is a signatory to the

SDG&E Settlement Motion, and as such, the Attachment 1 settlement agreement "is within the range of outcomes represented by the litigated positions of the parties as reflected in the existing record." (SDG&E Settlement Motion at 7.) Thus, we do not need to specifically address the battery technology issue that the Joint Minority Parties have raised. We do note, however, that SDG&E has incorporated the use of such batteries for its Reliability/Improvements activities.

Based on SDG&E's correction regarding the incorrect in-service dates, the 2014 actual-recorded expenses, and a comparison of the parties' positions to what was agreed in the settlement, the agreed upon settlement amounts for the capital projects for Reliability/Improvements is reasonable. Accordingly, the amounts agreed to in the Attachment 1 settlement agreement for the capital projects for Reliability/Improvements should be adopted: 2014 - $37.838 million; 2015 - $100.000 million; 2016 - $95.000 million.

6.2.2.1.5. Safety and Risk Management

The fifth category of costs under Electric Distribution Capital I are capital projects involving Safety and Risk Management. These are projects to address the mitigation of safety and physical security risks. As described in Exhibit 134, SDG&E proposes ten capital projects, including the following: (1) replacement of pad mounted electric distribution equipment with protective safety barriers to prevent exposure to live electric connections; (2) installation of a weather forecasting system to run weather models and generate forecasts; (3) acquisition of Powerworkz, which is a GIS work management system to manage vegetation management and transmission construction and maintenance; (4) various fire risk mitigation projects including improvements to circuit 1215, addressing pole loading issues, and hardening critical areas; (5) aviation hazard marking and lighting; (6) replace aging overhead infrastructure with new overhead and underground facilities as part of the legal agreement with Cleveland National Forest; and (7) replacement or removal of switches containing sulfur hexafluoride to reduce environmental risks from sulfur hexafluoride emissions. SDG&E requests the following: 2014 - $26.209 million for 2014; 2015 - $40.684 million for 2015, 2016 - $75.423 million 2016.

ORA contends that the Safety and Risk Management category is a new major area of capital investment projects. ORA notes however that SDG&E only spent about 64% of its 2014 forecast. Due to the underspending in 2014, ORA is not convinced that SDG&E will be able to achieve the forecasted expenditures for 2015 and 2016. ORA's recommended amounts essentially shifts SDG&E's initial forecasts by one year. ORA recommends the following for the Safety and Risk Management category: 2014 -$18.083 million; 2015 - $27.406 million; 2016 - $59.484 million.

MGRA claims that SDG&E's capital projects lacks specifics about how risk and safety will be affected. MGRA contends that SDG&E should develop methodologies and metrics to track spending for fire prevention, and to report that data as a metric in SDG&E's future GRCs to justify its fire prevention spending. MGRA further contends that SDG&E should present a detailed plan to accelerate the completion of its proposed fire risk mitigation activities.

SDG&E explains that because of the magnitude of its fire risk management activities, a ramp-up period was expected, which is why the 2014 actual-recorded costs were lower. SDG&E believes its forecasts are still accurate, and that the fire risk mitigation activities are achievable and can be completed.

On the issues raised by MGRA, SDG&E contends that fire risk continues to be a key focus for SDG&E. Contrary to MGRA's assertion that SDG&E has not relied on metrics, SDG&E contends that it used cost information from historical fire hardening projects and prior capital upgrades to develop its forecasts.

The settling parties have stipulated in the SDG&E Settlement Comparison Exhibit at 8 to the following: ORA's forecast of $18.083 million, plus $1.163 million, for a total amount of $19.246 million for 2014; and to SDG&E's requested amounts of $40.684 million, and $75.423 million, for 2015 and 2016, respectively.

None of the parties have contested the need for these Safety and Risk Management projects. However, MGRA questions whether SDG&E used appropriate metrics to justify its fire risk mitigation activities.

Based on SDG&E's testimony, SDG&E has provided sufficient support to justify its spending on fire risk mitigation activities. In addition, SDG&E's forecasted amounts are based in part on its historical spending on fire risk mitigation activities. Accordingly, we do not adopt MGRA's recommendation that SDG&E should be required to develop additional metrics to justify its fire risk mitigation activities.

Having reviewed the testimony of SDG&E and ORA, and comparing those positions to the amounts agreed upon in the Attachment 1 settlement agreement, the agreed upon amounts are reasonable as it reflects the 2014 actual recorded costs, and reflect SDG&E's commitment to complete the other phases of its fire risk mitigation activities. Accordingly, the following amounts for the capital projects associated with Safety and Risk Management should be adopted: 2014 - $19.246 million; 2015 - $40.684 million; 2016 - $75.423 million for 2016.

6.2.2.2. Electric Distribution Capital II

The second group of capital projects are those that are in the Electric Distribution Capital II category. This category of capital projects are comprised of the following: Overhead Pools; Mandated; Materials; Transmission/FERC Driven Projects; Equipment/Tools/Miscellaneous; and Smart Meter Program. SDG&E's forecast for the Electric Distribution Capital II capital expenditures are as follows: 2014 - $184.544 million; 2015 - $199.082 million; 2016 - $186.216 million.

In the SDG&E Settlement Comparison Exhibit at 8-9, the settling parties stipulated to the following for the Electric Distribution Capital II category: for 2014, to ORA's forecast of $113.902; a forecast of $199.082 million for 2015; and a forecast of $186.216 million for 2016.

6.2.2.2.1. Overhead Pools

The first category of capital projects under Electric Distribution Capital II is for Overhead Pools. The Overhead Pools reflect the costs that originate from central activities, and which are allocated to different capital projects.[30] Some examples of these costs are engineering capacity studies, reliability analysis, and preliminary design work.

There are four workgroup costs which make up the cost of the Overhead Pools. They are: (1) Local Engineering – Electric Distribution Pool; Local Engineering - Substation Pool; Department Overhead Pool; and Contract Administration Pool. As described in Exhibit 134, these four pools perform various functions, and are comprised of planners, designers, engineers, support personnel, managers, supervisors, dispatchers, field employees, clerical employees, and contract administrators.

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30 These central activities are also referred to as "pooled" or "indirect" costs.

SDG&E's recommended amounts for the Overhead Pools are as follows: 2014 - $108.552 million; 2015 - $118.357 million; and 2016 - $110.224 million.

ORA's analysis in Exhibit 376 focused on the costs for Local Engineering – Electric Distribution Pool, and Local Engineering – Substation Pool. These two subcategories account for over 90% of these Overhead Pools cost. ORA compared SDG&E's forecasts to various years, and questioned SDG&E's use of the 2013 data to develop its forecast for the Electric Distribution Pool subcategory. Instead of using 2013 as the basis for calculating the Electric Distribution Pool, ORA used 2014 as the basis, and applied a 25.7% factor to the Electric Distribution Pool to derive its forecasts for 2015 and 2016. For the Substation Pool subcategory, ORA accepted and applied SDG&E's 24.5% factor and used that to forecast the 2015 amount. ORA accepted SDG&E's 2016 forecast of the Substation Pool subcategory.

As a result of ORA's analysis, as summarized above and as described in Exhibit 376, ORA recommends the following amounts for Overhead Pools: 2014 - $63.826 million; 2015 - $90.361 million; 2016 - $108.345 million.

Although ORA agrees with SDG&E's methodology for determining its forecasts for the four subcategories under Overhead Pools, ORA and SDG&E disagree on the overall amount of capital projects for electric distribution. SDG&E contends that if this same methodology is applied to ORA's recommended amount of capital projects, that ORA's recommended forecasts for 2015 and 2016 should be higher by $4.000 million and $3.800 million, respectively.

In the SDG&E Settlement Comparison Exhibit at 8-9, the settling parties stipulated to ORA's recommended amount of $63.826 million for 2014, and to

SDG&E's requested amounts of $118.357 million for 2015, and $110.224 million for 2016.

ORA's recommended amount of $63.826 million for 2014 is based on the 2014 actual recorded amount for Overhead Pools. For 2015 and 2016, although SDG&E's forecasted amounts are higher than what ORA forecasted, SDG&E explained in Exhibits 134 and 136 that the expenses in Overhead Pools are increasing due to an increased focus on risk reduction, which requires more engineering work, increased reliance on detailed engineering studies and designs for its electric distribution system, and the use of more advanced tools. Taking this into account, we find that the following amounts presented in the Attachment 1 settlement agreement are reasonable and should be adopted: 2014 - $63.826 million; 2015 - $118.357 million; 2016 - $110.224 million.

6.2.2.2.2. Mandated

The second category of capital projects under Electric Distribution Capital II is for Mandated projects. Mandated projects are projects required by the Commission and other regulatory agencies. These types of projects help promote public safety and employee safety. As described in Exhibit 134, there are five capital projects under the Mandated category: corrective maintenance program for the inspection of overhead and underground electric distribution facilities;[31] corrective maintenance program for underground switch replacement and manhole repairs; load research and dynamic load profile electric metering as mandated by Title 20 of the California Code of Regulations; avian protection program to prevent the electrocution of birds in compliance with State and

[31] This is an ongoing program mandated under the Commission's GO 95, 128 and 165.

Federal laws; and pole replacement and reinforcement of in-service distribution poles. SDG&E requests the following for the Mandated projects: 2014 - $37.872 million; 2015 - $38.148 million; 2016 - $39.063 million.

ORA recommends that the actual recorded amount of $29.118 million be adopted for 2014. ORA accepts SDG&E's forecasts for 2015 and 2016.

In the SDG&E Settlement Comparison Exhibit at 8-9, the settling parties stipulate to ORA's forecast of $29.118 million for 2014, and to the undisputed amounts of $38.148 million and $39.063 million for 2015 and 2016, respectively.

As described in the testimony of SDG&E and ORA, these Mandated projects are ongoing projects that are in compliance with various regulatory requirements. None of the parties dispute the need for these projects. Accordingly, the following amounts are reasonable and should be adopted: 2014 - $29.118 million; 2015 - $38.148 million; 2016 - $39.063 million.

6.2.2.2.3. Materials

The third category of capital projects under Electric Distribution Capital II is for Materials. As described in Exhibit 134, the Materials project is needed to purchase transformers, supply new and replacement equipment, and to maintain inventory at each electric distribution service center. SDG&E requests the following: 2014 - $21.024 million; 2015 - $22.025 million; 2016 - $23.027 million.

ORA recommends that the adjusted-recorded expense of $12.781 million for 2014 be used. Due to the historical spending trend, ORA recommends the lower amount of $15.605 million for 2015. For 2016, ORA accepts that spending will trend back towards the level that SDG&E recommends, and accepts SDG&E's 2016 forecast amount of $23.027 million.

SDG&E contends that ORA's 2015 forecast did not take into account the incremental increase in the unit cost of the transformers as a result of SDG&E's

replacement of mineral oil with another fluid as the transformer insulating medium. In addition, SDG&E contends that ORA's 2015 forecasted amount did not take into the delay in receiving materials from orders in 2014 for materials.

In the SDG&E settlement agreement, parties stipulated to ORA's recommended amount of $12.781 million for 2014, and to SDG&E's requested amounts of $22.025 million for 2015, and $23.027 million for 2016.

Based on the testimony of SDG&E and ORA, the agreed upon amounts in the Attachment 1 settlement agreement for the Materials project is reasonable because it reflects the actual recorded amounts for 2014, as well as the higher costs for transformers that increases the 2015 and 2016 costs. Accordingly, the following amounts for Materials should be adopted: 2014 - $12.781 million; 2015 - $22.025 million; 2016 - $23.027 million.

6.2.2.2.4. Transmission/FERC Driven Projects

The fourth category of capital projects under Electric Distribution Capital II is for the Transmission/FERC Driven projects. These capital projects cover transmission projects with a distribution component. The distribution component is funded through SDG&E's GRC. As described in Exhibit 134, there are 18 projects under this category, and include the following: (1) transmission line reliability projects to restore and repair affected facilities; (2) transmission line relocation projects; (3) replacement and relocation of the South Bay substation; (4) installation of new substation projects or rebuilding of existing substations; (5) installation, upgrade, and expansion of SDG&E's fiber optic communication system for control and protection of transmission and distribution lines, and automation; (6) improve the reliability of certain transmission lines in the Cleveland National Forest, which is in a fire and wind-prone area, by replacing about 1384 wood poles with steel poles, and about

105 circuit miles of lines; (7) fire harden certain transmission lines by replacing wooden poles with steel poles; and (8) enhance the reliability on certain transmission lines.

For the Transmission/FERC Driven projects, ORA recommends that the actual recorded expenses of $7.704 million be used for 2014. ORA does not dispute the need for the 18 projects, and agrees with SDG&E's forecast for 2015 and 2016.

In the SDG&E Settlement Comparison Exhibit at 8-9, the settling parties stipulate to ORA's forecast of $7.704 million for 2014, and agree to SDG&E's forecasted amounts of $19.180 million and $12.530 million for 2015 and 2016, respectively.

Based on the testimony of SDG&E and ORA, the amounts proposed in the Attachment 1 settlement agreement are reasonable and supported by the evidence presented. The projects under the Transmission/FERC Driven category are in compliance with FERC directives, promote fire safety, and/or improve the reliability of SDG&E's transmission and distribution system. None of the parties disagree with SDG&E's forecast for 2015 and 2016. Thus, the following amounts for the Transmission/FERC Driven category should be adopted:
2014 - $7.704 million; 2015 - $19.180 million; 2016 - $12.530 million.

6.2.2.2.5. Equipment/Tools/Miscellaneous

The fifth category of capital projects under Electric Distribution Capital II is for Equipment/Tools/Miscellaneous. This category of capital expenditures is for the purchase of new electric distribution tools and equipment to be used by field personnel to inspect, operate and maintain SDG&E's electric distribution system. SDG&E's forecast for Equipment/Tools/Miscellaneous for 2014, 2015, and 2016, is $1.372 million for each year.

ORA recommends that the actual recorded amount of $0.388 million be adopted for 2014. ORA accepts SDG&E's forecast of $1.372 million annually for 2015 and 2016 because it follows the historical spending pattern.

In the SDG&E Settlement Comparison Exhibit at 8-9, the settling parties stipulate to ORA's forecast of $0.308 million for 2014, and to SDG&E's forecast for 2015 and 2016 of $1.372 million annually.

The amounts proposed in the Attachment 1 settlement agreement are reasonable and supported by the testimony as described above. Accordingly, the following amounts should be adopted for the Equipment/Tools/Miscellaneous category of capital expenditures: 2014 - $0.308 million; 2015 - $1.372 million; 2016 – $1.372 million.

6.2.2.2.6. Smart Meter Program

The sixth category of capital projects under Electric Distribution Capital II is for the Smart Meter Program. This category of capital expenditures is to "replace the remaining smart meters that were unable to be installed by year end 2011." (Exhibit 134 at 132.) At the time SDG&E's GRC application was prepared, approximately 2.288 million smart meters had been deployed. In 2014, SDG&E requested funding for the installation of 2,800 more units. The project was scheduled to be completed in 2014.

ORA recommends that the actual recorded amount of $0.165 million in 2014 should be adopted.

The settling parties have stipulated in the SDG&E Settlement Comparison Exhibit at 9 to ORA's forecast of $0.165 million.

SDG&E did not contest ORA's recommendation to use the actual recorded amount for 2014. Based on that actual recorded amount to complete the installation of the smart meters, the amount proposed in the Attachment 1 settlement agreement of $0.165 million for 2014 is reasonable and should be adopted. There are no forecasted amounts for 2015 and 2016.

6.2.2.3. Summary of Electric Distribution Capital Costs

Summarizing the discussions above regarding the Electric Distribution Capital I and Electric Distribution Capital II projects for 2014 to 2016, we conclude the amounts proposed in the Attachment 1 settlement agreement of the SDG&E Settlement Motion are reasonable and should be adopted.

For Electric Distribution Capital I, the following amounts should be adopted: 2014 - $145.552 million; 2015 - $280.772 million; 2016 - $296.428 million.

For Electric Distribution Capital II, the following amounts should be adopted: 2014 - $113.902 million; 2015 - $199.082 million; 2016 - $186.216 million.

6.2.2.4. Distributed Generation Impact Study

In the Attachment 5 Settlement Agreement of the SDG&E Settlement Motion, SDG&E has agreed with TURN and UCAN that SDG&E will perform and present a study of the distributed generation impacts on circuit peak loads prior to the filing of SDG&E's next GRC application. At a minimum, the study is to aggregate circuits with similar load profiles to better estimate the potential of distributed generation to reduce circuit peaks and distribution expenditures in future GRCs.

None of the parties have objected to this provision of the Attachment 5 Settlement Agreement.

This provision of the Attachment 5 Settlement Agreement is reasonable and should be adopted. Such a study will provide insight on whether distributed generation will impact the need for additional capacity.

6.2.3. O&M Distribution Costs for Gas Operations

The gas distribution O&M costs appear at line 4 of SDG&E's gas summary of earnings table.[32] The gas distribution network of SDG&E consists of about 8000 miles of gas main pipelines, about 6600 miles of service lines, and 860,000 meters. These lines are made up of various diameters, and are constructed of both steel and plastic. There are also associated gas distribution facilities such as valves and regulators.

As shown in the SDG&E Comparison Exhibit at 335, for the O&M costs associated with SDG&E's gas distribution, SDG&E requested updated O&M costs of $25.198 million for gas distribution. ORA had proposed that the O&M costs for gas distribution be set at $22.408 million.[33] The SDG&E Settlement Agreement agrees to $23.996 million in O&M costs.[34]

The gas distribution O&M costs consist of various activities to operate and maintain its pipelines and associated equipment in good working order in order to provide safe and reliable gas service to all of its customers who use natural gas. The work is performed by a trained and skilled workforce, and includes construction crews, technical planners, and engineers. There are about 340 gas distribution employees, who operate out of five bases and one technical office.

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[32] SDG&E's gas summary of earnings table appears in: the SDG&E Settlement Comparison Exhibit at 335; Exhibit 219, Table KN-6; and the Update Testimony of SDG&E and SoCalGas, Table KN-6.

[33] This updated amount of $22.408 million is shown in SDG&E's gas summary of earnings table in Exhibit 367 at 16, and in the SDG&E Settlement Comparison Exhibit at 335. However, this amount varies from ORA's amount of $20.028 million shown in Exhibit 378 at 2, and in Exhibit 366 at 18.

[34] The O&M costs for SDG&E's DIMP is discussed in the section addressing SDG&E's gas transmission O&M costs.

According to SDG&E, the "level of funding requested in this testimony will allow compliance with pipeline safety regulations and the continued safe and reliable operation of SDG&E's gas distribution pipeline system." (Ex. 62 at 12.) In addition, all of these activities are consistent with the directives in Pub. Util. Code §§ 961 and 963 to develop and implement a plan for the safe and reliable operation of its gas pipelines, and to place the safety of the public and gas corporation employees as the top priority.

In preparing the forecasts of these costs, SDG&E reviewed historical spending levels, assessed future requirements for gas service, and considered the underlying cost drivers for the different kinds of activities. According to SDG&E, its "cost forecasts support the Company's goals of achieving operational excellence while providing safe and reliable delivery of natural gas to customers at reasonable cost, while mitigating risks associated with hazards to public and employee safety, infrastructure integrity and system reliability." (Ex. 62 at 4.)

Many of the gas distribution O&M costs are associated with ensuring the safety and reliability of SDG&E's gas operations. According to SDG&E, it "actively evaluates the condition of its pipeline system through maintenance and operations activities, and replaces pipeline segments to preserve the safe and reliable system customers expect." (Ex. 62 at 4.) These activities include such things as: performing leak surveys; evaluating and repairing main and service leaks; locating and marking facilities to avoid third party damage; replacement of aging pipelines and associated equipment; and documenting and maintaining records of its high pressure pipeline facilities.

In Exhibit 378, ORA took issue with seven of the twelve field operation expenses that make up the gas distribution O&M costs. ORA recommended slightly lower costs for these seven expenses based primarily on the use of the most recent recorded five-year average.

The agreed upon gas distribution O&M costs represents a compromise of the gas distribution costs that SDG&E and ORA had proposed. None of the other settling parties to the SDG&E settlement motion oppose the gas distribution costs that were agreed upon. In addition, none of the parties who filed comments on the SDG&E settlement motion, or who have filed briefs, oppose the gas distribution O&M costs. Based on the testimony of the witnesses for SDG&E and ORA on the gas distribution O&M costs, the agreed upon settlement amount of $23.996 million for the O&M costs is reasonable and should be adopted. This amount will provide the necessary funding for SDG&E to carry out the daily O&M activities to operate the gas distribution system in a safe and reliable manner.

6.2.4. Distribution Capital Expenditures for Gas Operations

For the capital expenditures associated with SDG&E's gas distribution, SDG&E requested the following capital expenditures: 2014 - $32.378 million; 2015 - $37.363 million; and 2016 - $40.971 million.[35] (See Exhibit 62.) ORA had proposed that the capital expenditures for gas distribution be set at the following: 2014 - $32.821 million; 2015 - $37.363 million; and 2016 - $40.971 million. (See Ex. 378 at 3, 21.) The SDG&E Settlement Agreement

[35] The DIMP related capital expenditures are discussed with the TIMP in the gas transmission capital expenditures section of this decision.

recommends adoption of the following capital expenditures:
2014 - $32.821 million; 2015 - $37.363 million; and 2016 - $40.971 million.[36]

The work activities associated with capital expenditures are performed daily, and are based on a variety of risk factors and work drivers. The work elements are prioritized based on a "review of maintenance activities and findings, results of field workforce inspections, and records of condition." (Ex. 62 at 8.) According to SDG&E, the capital expenditure activities respond to the operational, maintenance, and construction needs associated with projected customer and system growth, and the demands of local and state agencies. Such projects include: expanding the current system in order to provide service to new customers; improving system capacity to accommodate customer and/or load growth; and relocation of pipelines and associated facilities to accommodate the needs of local and state agencies.

According to ORA's testimony in Exhibit 378, it reviewed SDG&E's capital expenditure forecast for 2014, 2015, and 2016. ORA also reviewed SDG&E's recorded capital expenditures for 2014. ORA recommended in its testimony that the Commission adopt the recorded 2014 costs, and accepts the 2015 and 2016 forecasts of SDG&E.

Based on the testimony of SDG&E and ORA concerning the gas distribution capital expenditures, the agreed upon amounts in the SDG&E Settlement Agreement are reasonable, as it will provide sufficient funds to make

[36] The SDG&E Settlement Agreement does not specify the separate amounts for the gas distribution capital expenditures. Instead, the SDG&E Settlement Agreement lists the total capital expenditures for the operational activities associated with gas distribution, transmission, engineering, and pipeline integrity. (See SDG&E Settlement Comparison Exhibit at 6, 307, 330, and 341.) We have based the amounts for the gas distribution capital expenditures on ORA's testimony and the references noted in the SDG&E Settlement Comparison Exhibit.

continuing improvements to its gas distribution system so that it can safely and reliably deliver its natural gas to its customer. Accordingly, the following gas distribution capital expenditures should be adopted: 2014 - $32.821 million; 2015 - $37.363 million; and 2016 - $40.972 million.

6.3. Gas Transmission

6.3.1. O&M Gas Transmission Costs

Line 5 of SDG&E's combined summary of earnings table, and its gas summary of earnings table displays the O&M costs of SDG&E's gas transmission costs.

For SDG&E's gas transmission O&M costs, SDG&E requested updated O&M costs of $4.631 million for gas transmission. ORA proposed that the O&M costs for gas transmission be set at $4.172 million. The SDG&E Settlement Agreement agrees to $4.663 million in O&M costs.

The O&M costs consist of the day-to-day expenses to operate and maintain SDG&E's gas transmission system. These expenses are associated with pipeline operations, gas compression operations, and field engineering and technical support services. According to SDG&E, the key objectives of the gas transmission unit "are to operate safely, achieve compliance with applicable legal and regulatory requirements, and provide customers with reliable natural gas service at reasonable cost." (Ex. 40 at 2.)

SDG&E's request for the TY 2016 O&M costs for gas transmission are based on increased regulatory requirements and changes in SDG&E's policy relating to the maintenance and enhancement of the integrity of the transmission pipeline system. According to SDG&E, these additional costs are attributable to: the escalating pipeline safety fee to the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration

(PHMSA); knowledge management and succession staffing; pipeline district workload increase; and incremental O&M costs associated with post- Pipeline Safety Enhancement Program (PSEP) activities.

The daily O&M of SDG&E's gas transmission operations is performed by SDG&E employees, along with technical engineering support provided by SDG&E's Gas Transmission Technical Services unit. The managerial leadership over SDG&E's gas transmission unit and O&M activities is provided by SoCalGas' Gas Transmission and System Operations unit. The services provided by this SoCalGas unit are billed to SDG&E, which is a component of SDG&E's gas transmission O&M costs.

ORA had recommended that SDG&E's O&M request of $4.663 million be reduced by $491,000. ORA's proposed reduction was primarily based on lower recorded costs.

Based on the testimony of SDG&E and ORA on gas transmission, it is reasonable to adopt the agreed upon O&M costs of $4.663 million contained in Attachment 1 of the SDG&E Settlement Motion. Such an amount will provide SDG&E with the funds necessary to safely and reliably operate its gas transmission system. The O&M amount of $4.663 million should be adopted.

6.3.2. Gas Transmission Capital Expenditures

We address the capital expenditures for TIMP and DIMP in this section of the decision.[37]

[37] SDG&E's O&M costs for TIMP and DIMP are discussed in the gas engineering section.

For the capital expenditures associated with SDG&E's TIMP and DIMP, SDG&E requested the following capital expenditures: 2014 - $7.957 million; 2015 - $6.790 million; and 2016 - $24.215 million. (See Exhibit 53.)

ORA proposed that the capital expenditures for TIMP and DIMP be set at the following: 2014 - $9.969 million; 2015 - $6.790 million; and 2016 - $24.215 million. (See Exhibit 378 at 37.)

The SDG&E Settlement Agreement recommends adoption of the following capital expenditures: 2014 - $9.969 million; 2015 - $6.790 million; and 2016 - $24.215 million.[38]

The work activities associated with the TIMP and DIMP capital expenditures are performed on a continuing basis. These activities evaluate the transmission and distribution pipeline systems through data gathering and inspections, and then action is taken to mitigate or remediate the identified risks. According to SDG&E, these capital expenditures support SDG&E's "core goals of providing safe and reliable service at reasonable cost." (Ex. 53 at 18.)

In Exhibit 378, ORA reviewed SDG&E's capital expenditure forecast for 2014, 2015, and 2016. ORA also reviewed SDG&E's recorded capital expenditures for 2014. ORA recommended in its testimony that the recorded 2014 expenditures, and the 2015 and 2016 forecasts of SDG&E, be adopted.

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[38] As mentioned earlier, the SDG&E Settlement Comparison Exhibit at page 6 does not specify the separate amounts for the gas engineering (including TIMP and DIMP) capital expenditures. Instead, the SDG&E Settlement Comparison Exhibit lists the total capital expenditures for gas distribution, transmission, engineering, and pipeline integrity. (See SDG&E Settlement Comparison Exhibit at 6, 68-70, 307, 330, and 341.) We have based the amounts for the TIMP and DIMP capital expenditures on ORA's testimony and the references noted in the SDG&E Settlement Comparison Exhibit.

Based on the testimony of SDG&E and ORA concerning the TIMP and DIMP capital expenditures, the agreed upon amounts in the SDG&E Settlement Agreement are reasonable, as it will provide sufficient funds to perform the work required by the TIMP and DIMP. Accordingly, the following TIMP and DIMP capital expenditures should be adopted: 2014 - $9.969 million; 2015 - $6.790 million; and 2016 - $24.215 million.

In finding that the TIMP and DIMP capital expenditures are reasonable, we are also approving the method by which SDG&E and SoCalGas will identify and replace certain pipelines known to pose hazards, such as plastic pipeline installed before 1986, which is made of Aldyl-A. However, we note that the companies' discussion of how it will go about prioritizing this work is as yet incomplete. The SoCalGas and SDG&E Distribution Risk Evaluation and Monitoring System (DREAMS) represents a proactive approach to the problem and is a programmatic replacement of plastic distribution pipelines. SDG&E and SoCalGas stated in response to a data request that their average rate of replacement for plastic mains in 2014 under DREAMS (the program's first year) was 1.50 and 1.25 miles per year, respectively, and that the rate of replacement is proposed to increase to 17 miles per year. Even with that increased pace of work, the estimated 9,442 miles (SoCalGas) and 1,638 miles (SDG&E) of plastic Aldyl-A pipe in the utilities' systems will take many years to completely replace this pipe.

We raise this to point out a real-world example of how a robust risk identification and risk management approach can assist the utilities in identifying hazards, and how this can assist the Commission in prioritizing the expedient mitigation of identified risks. As discussed earlier, the Commission's S-MAP and RAMP proceedings are expected to be fully implemented by the next

GRC filing, which we anticipate will provide a more uniform way to examine and treat infrastructure risks.

6.4. Generation

Line 7 of SDG&E's summary of earnings tables display the O&M costs of its generation costs associated with its electric and gas operations.

6.4.1. Electric Generation O&M Costs

SDG&E's electric generation costs cover the following three primary workgroups: Generation Plant; Resource Planning; and Administration.

The Generation Plant group, which accounts for more than 90% of SDG&E's O&M and capital expenditures in electric generation, owns and operates four electric generation plants. These electric generation plant are the following: the 565 megawatt (MW)[39] Palomar Energy Center located in Escondido (Palomar); the 480 MW Desert Star Energy Center located in Boulder City, Nevada (Desert Star); the 92 MW Miramar Energy Facility located in San Diego (Miramar); and the 45 MW Cuyamaca Peak Energy Plant located in El Cajon (Cuyamaca). Palomar and Desert Star are combined cycle power plants[40] while the Miramar and Cuyamaca Plant are peaking plants used during periods of high demand.

SDG&E's Resource Planning group is responsible for planning the long-term electric generation needs of its bundled customers. Resource Planning is

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[39] The MW rating represents the full load at design conditions.

[40] Combined cycle power plants use an assembly of heat engines that work in tandem from the same source of heat. Combining two or more thermodynamic cycles results in improved overall efficiency and reduced fuel costs.

responsible for producing SDG&E's long-term procurement plan and energy resource recovery account forecast.

The Administration group provides direction and managerial oversight of SDG&E's entire Power Supply organization.[41] Administration also provides managerial oversight and analytical support for SDG&E's generating fleet.

For TY 2016, SDG&E is requesting $53.864 million for O&M costs which is $11.001 million more than its 2013 adjusted-recorded amount.

ORA recommends electric generation O&M costs of $47.611 million.[42] As described in Exhibits 366 and 377, ORA recommends reductions in O&M costs primarily for Desert Star, Generation Plant, and Resource Planning.

As described in SDG&E's rebuttal testimony in Exhibit 77, SDG&E disagrees with ORA's recommended reductions.

In the SDG&E Settlement Comparison Exhibit at 9 and 334, the settling parties agreed to an amount of $52.802 million for Electric Generation O&M costs for TY 2016. This amount is $1.062 million less than SDG&E's proposed costs.

SDG&E provided its forecast of O&M costs for its four generating facilities, and evidence supporting those costs in Exhibits 74 and 77. ORA presented its testimony on electric generation costs in Exhibit 377. We reviewed the testimony of SDG&E and ORA, and compared their recommendations to the agreed upon amounts in the SDG&E Settlement Motion. Based on that testimony, the agreed upon settlement amount of $52.802 million for the electric generation O&M costs

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[41] The Power Supply organization encompasses the Electric Generation, Electric and Fuel Procurement, Smart Grid, Transmission Planning, and Major Outreach groups.

[42] In ORA's testimony in Exhibit 377, ORA originally recommended electric generation O&M costs of $46.887 million.

is reasonable, and should be adopted. This agreed upon amount will provide the necessary funds for SDG&E to continue to safely operate, and to maintain reliable operations, of SDG&E's electric generation assets.

6.4.2. Electric Generation Capital Expenditures

The capital expenditures requested by SDG&E for electric generation is composed of five major categories: (1) capital tools and test equipment; (2) Palomar operational enhancements; (3) Desert Star operational enhancements; (4) Miramar operational enhancements; and (5) Cuyamaca operational enhancements.

SDG&E requests the following electric generation capital expenditures: $21.736 million for 2014; $8.408 million for 2015; and $8.347 for TY 2016. The capital expenditures that SDG&E is requesting are described in detail in Exhibits 74 and 77. According to SDG&E, capital additions and improvements are continuous at all four generation facilities, and all of the capital projects being considered "increase the overall safety, reliability and operability and safety of the plants." (Exhibit 74 at 27.)

For the capital tools and equipment category, SDG&E originally requested $0.471 million annually for 2014, 2015 and 2016. The purchase of these tools and equipment enable plant personnel to work more efficiently and safely in maintaining the generation plant equipment. SDG&E subsequently agreed in Exhibit 77 with ORA's estimate of $0.164 million annually for 2014, 2015, and 2016.

For the Palomar operational enhancements, SDG&E requests $6.729 million for 2014, $4.161 million for 2015, and $2.796 million for 2016.

For the Desert Star operational enhancements, SDG&E requests $10.885 million for 2014, $1.734 million for 2015, and $4.480 million for 2016.

For the Miramar operational enhancements, SDG&E requests $2.223 million for 2014, $0.430 million for 2015, and $0.300 million for 2016.

For the Cuyamaca operational enhancements, SDG&E requests $1.428 million in 2014, $1.612 million in 2015, and $0.300 million in 2016.

In Exhibit 377, ORA proposes the following electric generation capital expenditures: $17.036 million for 2014; $3.162 million for 2015; and $5.526 million for TY 2016. ORA's recommendations for SDG&E's electric generation capital expenditures are described in more detail in Exhibit 377, and are summarized below by the five categories of capital expenditures.

For the tools and testing equipment, ORA recommends $0.164 million annually for 2014, 2015 and 2016.

For the Palomar capital improvements, ORA recommends $5.665 million in 2014, $1.385 million in 2015, and $0.622 million in 2016.

For the Desert Star capital improvements, ORA is recommending $9.183 million in 2014, $0.393 million in 2015, and $4.639 million in 2016.

For the Miramar capital expenditures, ORA is recommending $2.023 million in 2014, and $0.100 each for 2015 and 2016.

For the Cuyamaca capital expenditures, ORA recommends $0 for 2014, $1.083 million for 2015, and $0 for 2016.

SDG&E's rebuttal to ORA's recommended capital expenditure amounts are described in Exhibit 77. SDG&E accepted some of ORA's recommended capital expenditures, but disagreed with ORA on other recommendations.

In the SDG&E Settlement Comparison Exhibit at 9, the settling parties agreed to ORA's forecast of $17.036 million for capital expenditures in 2014. In addition, the settling parties agreed to SDG&E's forecast of $8.408 million and $8.347 million, in 2015 and 2016, respectively.

Based on the testimony of SDG&E and ORA regarding their positions on electric generation capital expenditures, and comparing it to the amounts agreed upon by the settling parties, the testimony supports the need for the upgrades and capital projects, as well as the reasonableness of the agreed upon costs. Accordingly, electric generation capital expenditures in the following amounts should be adopted: 2014 - $17.036 million; 2015 - $8.408 million; and 2016 - $8.347 million.

6.4.3. Gas Generation O&M Costs

The generation O&M costs shown at line 7 of SDG&E's gas summary of earnings table in the SDG&E Settlement Comparison Exhibit at 335 shows a settlement amount of $531,000. In its update testimony, SDG&E requested $552,000 while ORA recommended $429,000.

The gas generation O&M costs are derived from SDG&E's electric generation testimony in Exhibit 74 at 25. Those O&M costs are allocated to SDG&E's electric and gas operations. (See Ex.219, at Tables KN-14, KN-15, and KN-18.) As shown in SDG&E's gas summary of earnings table, the settling parties agree to an allocation of $531,000 to SDG&E's gas operations.

No one raised any objection to the gas generation O&M cost of $531,000. Based on the amount that SDG&E requested, and what ORA recommended, the agreed upon settlement amount of $531,000 for O&M costs for gas generation is reasonable, and should be adopted.

6.5. Nuclear Generation (SONGS)

This section discusses SDG&E's O&M costs relating to its 20% minority ownership in SONGS. SCE is the majority owner. Traditionally, SDG&E recovers most of the costs associated with its 20% ownership interest in SONGS based on the SONGS portion of SCE's GRC. SDG&E's SONGS-related costs that are not addressed in SCE's GRC, such as Unit 1 Spent Fuel Storage, Navy site easements, insurance, property taxes and capital related costs, were typically recovered in SDG&E's own GRC.

With the decommissioning of SONGS, announced by SCE on June 7, 2013, most of SDG&E's operating costs relating to SONGS have ended. Despite the cessation of operations, costs will continue to be incurred during the decommissioning phase which is expected to take approximately forty years to complete. SDG&E plans to recover most of these costs through regulatory mechanisms other than this GRC.

As described in Exhibit 80, SDG&E is likely to seek recovery of certain unique SONGS-related costs in its GRC for the following: Unit 1 offsite spent fuel storage, the Master Insurance Program (MIP) worker's compensation costs, marine mitigation costs, escalation, capital and related costs, and SDG&E oversight.

Line 8 of SDG&E's combined summary of earnings table shows the O&M costs for SDG&E's nuclear generation costs. For its TY 2016 GRC application, SDG&E seeks recovery of the following two SONGS-related O&M costs which total to $1.293 million: $1.064 million for SONGS Unit 1 offsite spent fuel costs; and $0.229 million for Workers' Compensation under the MIP.

The spent fuel assemblies from SONGS Unit 1 are stored in Illinois. SCE makes monthly payments for this storage, and bills SDG&E for its 20% share. SDG&E estimates its test year 2016 expense to be $1.064 million.

The MIP, which was in effect from 1972 to 1999, insured all the owners, contractors and subcontractors under one insurance program for General Liability and Workers' Compensation. Although premiums are no longer paid into the MIP, there are still open claims that are the responsibility of the SONGS owners. The amount of $0.229 million that SDG&E forecasts in this GRC represents the actual 2012 cost for workers' compensation billed to SDG&E by SCE, for its 20% ownership interest in SONGS.

In addition to the cost items mentioned above, SDG&E requests that the Commission make a finding in this proceeding that SDG&E be allowed to update its revenue requirement for its 20% share of SONGS-related marine mitigation costs and escalation to reflect the Commission's final authorized amounts established in SCE's TY 2015 GRC. The costs associated with marine mitigation are incurred for ongoing projects to mitigate the turbidity effects caused by movement of ocean water used to cool SONGS when it was operational. Marine mitigation costs are being recovered through SCE's GRC.

ORA does not disagree with the amounts being proposed by SDG&E for the Unit 1 offsite spent fuel storage, and for the MIP. However, ORA contends that the amounts being requested in this GRC are moot and unnecessary since these costs are being tracked in a two-way balancing account established pursuant to D.06-11-026. As such, any amounts in excess of costs actually billed are being tracked, and are subject to a reasonableness review.

SDG&E agrees with ORA that the Unit 1 offsite spent fuel storage and MIP costs are tracked in a balancing account. However, SDG&E contends that this balancing account is not subject to reasonableness review.

In the SDG&E Settlement Comparison Exhibit at 336, the settling parties agree to SDG&E's forecast of $1.064 million for Unit 1 offsite spent fuel storage, and to SDG&E's forecast of $0.229 million for MIP.

In Exhibit 80, the SONGS witness for SDG&E stated that SDG&E may seek to recover Unit 1 Spent Fuel Storage costs in SDG&E's Energy Resource Recovery Account (ERRA) proceeding rather than through its GRC proceeding. In

A.15-04-014, filed on April 15, 2015, SDG&E included $1.077 million for its SONGS Unit 1 offsite spent fuel storage costs. In D.15-12-032, the Commission authorized SDG&E to recover the $1.077 million for the Unit 1 offsite spent fuel storage costs. Since the Commission has already granted SDG&E to recover $1.077 million in SDG&E's ERRA proceeding, the amount of $1.064 million that SDG&E requested in this proceeding for the Unit 1 offsite spent fuel storage costs for TY 2016 is removed from consideration in this GRC. As a result, the agreed upon amount of $1.293 million for nuclear generation costs should be reduced to $229,000.

With respect to the $229,000 being requested for the MIP costs, this amount represents the actual costs billed by SCE to SDG&E for its 20% minority share in SONGS. The settling parties agreed on this amount, and no other party has objected to this amount or to the inclusion of such costs in this GRC.

Accordingly, it is reasonable to adopt the agreed upon amount of $229,000 for SDG&E's nuclear generation O&M costs.

SDG&E is authorized to continue the two-way SONGS balancing account through this rate cycle.

SDG&E's request that it be allowed to update its revenue requirement to reflect its 20% share of SONGS-related marine mitigation costs and escalation authorized by the Commission in SCE's TY 2015 GRC, is granted. This update shall be filed via a Tier 1 advice letter, within 15 days from the effective date of this decision through a Tier 1 advice letter.

6.6. Engineering

Line 9 of SDG&E's summary of earnings tables reflect the O&M costs associated with the engineering costs for both its electric and gas operations.

6.6.1. Electric Engineering O&M Costs

As shown at line 9 of SDG&E's electric summary of earnings table in Table KN-2, and in Table KN-21 of SDG&E's Exhibit 210 and its update testimony, SDG&E requested O&M costs of $0.584 million for engineering for its electric operations. This forecasted amount is based on certain engineering costs (gas engineering and public awareness) as described in Table KN-21 of Exhibit 219.

ORA recommended the amount of $0.224 million for the O&M engineering costs for SDG&E's electric operations. (See SDG&E Settlement Comparison Exhibit at 334.) As described in Exhibit 378, ORA's recommended amount is based in part on the 2014 recorded costs, and the five year average of 2010-2014.

In the electric summary of earnings table in the SDG&E Settlement Comparison Exhibit at 334, the parties have agreed upon the amount of $0.330 million for the engineering O&M costs for SDG&E's electric operations.

Based on the testimony of SDG&E and ORA, and the recorded costs, it is reasonable to adopt the agreed upon amount $0.330 million as the O&M engineering costs for SDG&E's electric operations.

6.6.2. Gas Engineering O&M Costs

As shown at line 9 of SDG&E's gas summary of earnings table in Table KN-6, and in Table KN-22 of SDG&E's Exhibit 219, SDG&E requested O&M costs of $11.710 million for O&M engineering costs for its gas operations. The cost components which make up this line item consist of the following: gas engineering of $65,000; gas engineering public awareness of $69,000; total TIMP and DIMP of $11.484 million; and gas engineering codes and standards of $92,000. (See Exhibit 219, Table KN-22.)

In the SDG&E Settlement Comparison Exhibit at 335, the gas engineering costs shown at line 9 of SDG&E's gas summary of earnings table shows a settlement amount of $11.589 million.

The gas engineering O&M costs consist of various activities that provide technical guidance to support the day-to-day functions for gas transmission, gas distribution, and gas storage. According to SDG&E, these gas engineering activities consist of: creating and issuing policies and standards that help establish and validate compliance with applicable laws, regulations and internal policies; providing and issuing engineering designs primarily for gas transmission and gas distribution projects; and making capital investments that support the safety and reliability of the transmission system.

SDG&E states that these costs "support SDG&E's goal to continually enhance pipeline safety and help maintain reliability by making necessary and prudent investments," including adding resources for quality assurance and quality control systems. (Exhibit 29 at 4.) In addition, gas engineering utilizes a process hazard analysis to identify and re-engineer out potential hazards.

As mentioned above, the line item for gas engineering includes the O&M costs for the TIMP and the DIMP. These two pipeline integrity management programs focus on identifying and addressing the risks to transmission and distribution pipelines as required by Subparts O (TIMP) and P (DIMP) of Part 192 of Title 49 of the Code of Federal Regulations. Both the TIMP and DIMP require that assessments and evaluations of these pipelines take place on a regular basis.

For the TY 2016 O&M cost for the TIMP, SDG&E requests that the amount of $5.451 million be adopted. The O&M activities for the TIMP include the following: performing threat identification and risk assessment; creating and maintaining an assessment plan; performing assessments; taking remedial action; evaluating and taking additional preventative and mitigation measures; managing the GIS flow; and addressing audit and reporting needs.

For the TY 2016 O&M cost for the DIMP, SDG&E requests that $6.033 million be adopted. The O&M activities for the DIMP include the following: understanding of the attributes of the distribution system; identifying threats and performing risk assessments; developing programs and activities to address risks; managing the GIS flow; and carrying out compliance, auditing, and reporting functions.

ORA recommends that the total O&M costs for gas engineering be set at $9.379 million. ORA recommended that SDG&E's O&M TIMP costs be reduced from $5.451 million to $4.490 million due to the recorded TIMP cost of $4.853 million in 2014. Similarly, ORA recommended that the TY 2016 O&M cost for the DIMP be set at the recorded 2014 amount of $4.808 million, instead of SDG&E's request of $6.033 million.

The settling parties have agreed to a gas engineering amount of $11.589 million, and specifically agree to TIMP and DIMP costs of $11.484 million. (See SDG&E Settlement Comparison Exhibit at 6, 335, and 336.) The agreed upon gas engineering O&M costs represents a compromise of the gas engineering costs that SDG&E and ORA had proposed. None of the other parties oppose the gas engineering O&M costs.

Based on the testimony of the witnesses for SDG&E and ORA on the gas engineering costs, the agreed upon settlement amount of $11.589 million for the O&M engineering costs for SDG&E's gas operations is reasonable. This amount it slightly less than what SDG&E had requested in its application, while taking into consideration the 2014 recorded costs and the requirements of the TIMP and

DIMP. This amount will provide the necessary funding for SDG&E to carry out the daily gas engineering O&M activities to support the safe and reliable operation of the gas transmission and gas distribution systems. Accordingly, the gas engineering O&M cost of $11.589 million should be adopted.

As part of the Attachment 5 Settlement Agreement of the Applicants' Settlement Motions, TURN, UCAN, and the Applicants agreed that each utility will continue to maintain separate two-way balancing accounts for the TIMP and DIMP expenditures, and agreed on the process for recovery of undercollected amounts.

None of the parties have objected to these provisions regarding the TIMP and DIMP.

Since the TIMP and DIMP costs may vary, depending on federal regulatory action, it is reasonable to continue the two-way balancing account treatment for the TIMP and DIMP costs, and to establish a procedure to recover the undercollected amounts. This portion of the Attachment 5 Settlement Agreement should be adopted.

6.6.3. Gas Engineering Capital Expenditures

For the capital expenditures associated with SDG&E's gas engineering, SDG&E requested the following capital expenditures: 2014 - $7.212 million; 2015 - $6.582 million; and 2016 - $7.002 million.[43] (See Exhibit 29 at 14.) ORA proposed that the capital expenditures for gas engineering be set at the following: 2014 - $7.365 million; 2015 - $6.582 million; and 2016 - $7.002 million. (See Exhibit 378 at 28.)

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[43] The capital expenditures for TIMP and DIMP were discussed earlier in the section addressing the gas transmission capital expenditures.

The SDG&E Settlement Agreement recommends adoption of the following capital expenditures for gas engineering: 2014 - $7.365 million; 2015 - $6.582 million; and 2016 - $7.002 million.[44]

The gas engineering capital expenditures are for projects to provide safe and reliable delivery of natural gas to customers at a reasonable cost. These activities include the following: installing new transmission pipelines; replacement and relocation of pipelines; maintaining and replacing key components of the compressor-related equipment; installation of cathodic protection to preserve the integrity of transmission pipelines from corrosion; securing necessary land rights; replacing meter and regulator equipment; and acquiring and replacing high-value tools that are used on transmission pipelines.

According to ORA's testimony in Exhibit 378, it reviewed SDG&E's capital expenditure forecast for 2014, 2015, and 2016, as well as SDG&E's recorded capital expenditures for 2014. ORA recommends in its testimony that the Commission adopt the actual-recorded 2014 costs, and accepts the 2015 and 2016 forecasts of SDG&E.

Based on the testimony of SDG&E and ORA concerning the gas engineering capital expenditures, the agreed upon amounts in the SDG&E Settlement Agreement are reasonable, as it will provide sufficient funds to make continuing improvements to its gas transmission system so that it can safely and reliably transport natural gas. Accordingly, the following gas engineering capital

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[44] See earlier footnote about how the SDG&E Settlement Agreement lists the total capital expenditures for gas distribution, transmission, engineering, and pipeline integrity. (See SDG&E Settlement Motion, SDG&E Settlement Comparison Exhibit at 6, 307, 330, and 341.) We have based the amounts for the gas engineering capital expenditures on ORA's testimony and the references noted in the SDG&E Settlement Comparison Exhibit.

expenditures should be adopted: 2014 - $7.365 million; 2015 - $6.582 million; and 2016 - $7.002 million.

6.7. Procurement

Line 10 of SDG&E's summary of earnings tables display the O&M costs of its electric procurement, and gas procurement.

6.7.1. Electric and Fuel Procurement O&M Costs

SDG&E's electric and fuel procurement costs are the costs associated with procuring, managing, planning, and administering SDG&E's electric and fuel supply for its bundled customers. The electric commodity expense is not included in the electric procurement O&M costs.

As described in Exhibit 84, SDG&E's electric procurement activities are necessary to ensure that SDG&E plans for, and acquires the necessary resources for use when needed. The procurement activities include meeting customer demand by bidding or scheduling energy resources into the wholesale energy and ancillary services markets. SDG&E purchases all of its electricity needs from the California Independent System Operator (CAISO) market. SDG&E also sells electricity to the CAISO markets to offset its energy procurement expenses. SDG&E's daily procurement process of purchasing and selling electricity in the CAISO market is conducted in accordance with the least cost dispatch requirements established by the Commission.

As shown at line 10 of SDG&E's electric summary of earnings table, SDG&E forecasts $8.647 million for the electric and fuel procurement O&M costs for TY 2016. (SDG&E Settlement Comparison Exhibit at 334.) The electric and fuel procurement O&M costs are derived from the combined procurement costs of $8.757 million as shown in SDG&E's combined summary of earnings table, and in Tables KN-23 through KN-27 as shown in Exhibit 219.

As described in Exhibit 84, the functions which comprise the electric and fuel procurement costs are as follows: long term procurement; trading and scheduling; and middle and back office.

ORA does not oppose SDG&E's electric and fuel procurement expense. (Exhibit 381 at 12.) In the SDG&E Settlement Comparison Exhibit at 337, the agreed upon amounts for the procurement O&M costs reflect the amounts that SDG&E recommended.

We have reviewed and considered the testimony presented by SDG&E and ORA, and compared that to the amount in the Attachment 1 settlement agreement of the SDG&E Settlement Motion. The agreed upon amount of $8.647 million for the electric fuel and procurement O&M costs is reasonable and is supported by the evidence. Accordingly, the amount of $8.647 million should be adopted for TY 2016 for SDG&E's electric and fuel procurement O&M costs.

6.7.2. Gas Procurement O&M Costs

The procurement O&M costs shown at line 10 of SDG&E's gas summary of earnings table shows a settlement amount of $0.110 million. ORA did not dispute this amount in its testimony.

As described earlier, the procurement O&M costs are derived from SDG&E's electric and fuel procurement testimony in Exhibit 74 at 1. As shown in SDG&E's gas summary of earnings table, and in Table KN-27 of Exhibit 219, $0.110 million is allocated to SDG&E's gas operations.

No one raised any opposition to the procurement O&M cost of $0.110 million. Based on the amount that SDG&E requested, and ORA's agreement with that amount, the agreed upon settlement amount of $0.110 million for procurement O&M costs for SDG&E's gas operations, is reasonable, and that amount should be adopted.

6.8. Customer Services

6.8.1. Electric and Gas Operations

Line 11 of SDG&E's summary of earnings tables show the O&M costs associated with customer services for its electric and gas operations. For its updated combined O&M costs for customer services, SDG&E requests a total of $89.628 million ($57.485 million for electricity; $32.143 million for gas).[45] The O&M costs for the line 11 description of customer services is derived from the updated O&M costs found in Exhibit 86 (customer services field - $21.925 million),[46] and Exhibit 101 (customer service operations, information, and technologies - $67.701 million). (See SDG&E Update Testimony, Table KN-28.)

The testimony of the SDG&E witnesses in Exhibits 86 and 101 address SDG&E's forecasted O&M costs for both non-shared and shared services. The O&M costs for the customer services field in Exhibit 86, and the O&M costs for customer service operations, information, and technologies in Exhibit 101, are then allocated to SDG&E's electric and gas operations as shown in Tables KN-28, KN-29, KN-30, KN-31, and KN-32 of Exhibit 219 and in SDG&E's update testimony.

As shown in Table KN-29 of SDG&E's update testimony, the O&M costs for customer services that SDG&E is requesting for its electric operations ($57.485 million) is derived from the O&M costs found in Exhibit 86 (customer services field - $5.333 million), and Exhibit 101 (customer service operations, information, and technologies - $52.152 million).

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[45] SDG&E originally requested combined O&M costs for customer services of $89.719 million ($57.445 million for electric; and $32.274 million for gas).

[46] As shown in Exhibit 86, SDG&E originally recommended $22.135 million for the customer services field O&M costs.

As shown at line 11 of SDG&E's electric summary of earnings table in Attachment 1 of the SDG&E Settlement Motion, the settling parties have agreed to $53.986 million for O&M costs for SDG&E's customer services field for its electric operations.

In Table KN-32 of SDG&E's update testimony, the O&M costs for customer services that SDG&E is requesting for its gas operations is $32.143 million. That amount is derived from the O&M costs found in Exhibit 86 (customer services field - $16.592 million), and Exhibit 101 (customer service operations, information and technologies - $15.551 million).

As shown at line 11 of SDG&E's gas summary of earnings table in Attachment 1 of the SDG&E Settlement Motion, the settling parties have agreed to $31.462 million for O&M costs for SDG&E's customer services field operations for its gas operations.

In the sections below, we first address the O&M costs associated with the customer services field costs for SDG&E's electric and gas operations. This is followed by the O&M costs associated with SDG&E's customer service operations, information and technologies.

For the capital expenditures related to customer services field, and to customer service operations, information, and technologies, the business justification for those costs are described in Exhibits 86 and 101. However, the funding requests for those capital expenditures are discussed in the IT section which follows.

6.8.1.1. Customer Services Field O&M Costs

As described in Exhibit 86, the customer services field operations for SDG&E's electric and gas operations engage in work activities to complete customer and company-generated work orders. SDG&E is requesting a total updated amount of $21.925 million for customer service field operations.

Most of the employees in the customer services field operations are field technicians who work out of five bases located in different areas of SDG&E's service territory. The customer-generated work activities include: establishing and terminating utility service; lighting gas pilots and conducting customer appliance checks; shutting off and restoring gas service for fumigation; investigating reports of gas leaks and responding to other emergencies; and investigating the cause of high bills. The company-generated work orders result in activities such as the following: performing meter and regulator changes and other related services at customer premises; and collecting customer payments for delinquent bills. Other activities that are part of the customer services field operations are the dispatching of emergency orders and work orders, and training-related activities.

As shown in Exhibit 86, most of the forecasted costs for customer services field are associated with costs relating to the operations cost category. The operations cost category includes labor and non-labor expenses for field technicians. The remainder of the customer services field costs is for activities related to supervision, dispatch, and support.

As discussed in Exhibit 353, ORA recommends $20.577 million for the customer services field costs. ORA agrees with SDG&E's forecast for the cost categories of supervision, and dispatch. However, for the reasons stated in Exhibit 353, ORA disagrees with SDG&E's proposed amounts for the cost categories of operations, and support. ORA recommends a $1.432 million reduction in the operations cost, and a $0.0126 million reduction in the support cost.

As described in their respective testimony, SDCAN, TURN, and UCAN recommended various reductions to the customer services field costs.

In the SDG&E Settlement Comparison Exhibit, it states at page 10 that the settling parties "stipulate to the SDG&E forecast of $22.135 million for Customer Service Field expenses." As noted earlier, the $22.135 million is SDG&E's original recommended amount, and not to the updated amount.

In Exhibit 88, SDG&E described its reasons for why the adjustments recommended for the customer services field costs by ORA, SDCAN, TURN, and UCAN should be rejected.

Based on the testimonies presented by SDG&E, ORA, SDCAN, TURN, and UCAN, and comparing their recommendations to the Attachment 1 settlement agreement of the SDG&E Settlement Motion, the agreed upon customer services field amount of $22.135 million is reasonable, and should be adopted. The agreed upon settlement amount is justified by SDG&E's methodology, and the various variables that affect the customer services field costs.

6.8.1.2. Customer Service Operations, Information, and Technologies O&M Costs

The other component that makes up the customer services O&M costs shown at line 11 of SDG&E's summary of earnings table are the costs associated with customer service operations, information, and technologies for its electric and gas operations. In its updated testimony, SDG&E requests a total of $67.703 million for these costs.[47]

[47] In Exhibit 101, SDG&E originally requested $67.584 million for these costs.

The costs associated with customer service operations, information, and technologies are described in Exhibit 101. The cost components which make up the $67.703 million are the following: non-shared customer service operations; non-shared customer service information; shared customer service operations; and shared customer service technologies, policies, and solutions. These costs represent the following kinds of activities provided to customers: metering, billing, credit and collections, remittance processing, postage, customer contact center, branch office, residential customer services, commercial and industrial services, communications and research, customer programs and projects, and technology services.

6.8.1.2.1. Non-Shared Customer Service Operations O&M

As described in Exhibit 101, the non-shared customer service operations O&M costs are composed of the following ten cost categories: (1) advanced metering; (2) meter reading; (3) billing; (4) credit and collections; (5) remittance processing; (6) postage; (7) branch offices; (8) customer contact center operations; (9) customer contact support; and (10) other office. Prior to its update testimony, SDG&E requested $36.479 million for these costs, which is more than its 2013 adjusted-recorded amount of $35.633 million.

The advanced metering operations support the delivery of customer-related services on the customer's premises, by responding to customer inquiries, resolving customer problems, and providing metering. The advanced metering operations involve the following activity areas: smart meter data operations, electric metering operations, quality assurance and training, meter and network engineering, and smart meter technical support. Prior to the settlement agreement, SDG&E requested $8.771 million.

In the SDG&E Settlement Comparison Exhibit at 10, the settling parties agree to a compromise forecast of $8.400 million for advanced metering.

The meter reading department was eliminated in 2012, as a result of the implementation of smart meters. SDG&E's forecast for this cost category is $0.

The billing activities cover the cost of calculating customer bills and maintaining accurate customer account information. The billing operation is comprised of three areas: customer billing; billing operations support; and customer billing resources. SDG&E originally requested $5.839 million for these costs, which is higher than its 2013 adjusted-recorded cost of $5.073 million.

In the SDG&E Settlement Comparison Exhibit at 10, the settling parties agree to ORA's forecast of $5.210 million for the billing operations.

Credit and collections is composed of three activities: credit and collections; customer payment services; and meter revenue protection. The credit and collections activities include traditional credit office functions such as credit policy and review, collection of delinquent accounts, management of outside collection agencies, and bankruptcy processing. Customer payment services consist of daily reconciliation and general ledger posting of payments. Meter revenue protection involves the investigation of energy theft and resolving safety issues due to such activity, and assisting in credit verifications involving non-payment by a customer. For TY 2016, SDG&E originally requested $2.848 million for the credit and collections cost category, which is an increase of $0.140 million over its adjusted-recorded 2013 amount of $2.708 million.

The cost category of remittance processing is for the costs associated with delivering customer bills, such as paper, envelopes, and vendor fees. SDG&E requested $875,000 for this category. SDG&E's request is lower than its 2013 adjusted-recorded amount of $887,000 because of the increasing use of electronic bills.

The cost category for postage is for the cost of mailing customer bills and notices. For TY 2016, SDG&E requested $4.333 million, which is less than its 2013 adjusted-recorded amount of $4.431 million. SDG&E's reduced amount is due to the increasing use of electronic bills.

The cost category of branch offices covers the cost of operating seven branch office facilities, and a third party vendor contract that provides a network of seventy five authorized payment locations (APLs). SDG&E requests $1.734 million for this cost category, which is less than its 2013 adjusted-recorded amount of $2.019 million. The reduction is due to the elimination of 5.5 full time equivalents (FTEs) due to process improvements. In addition, SDG&E is requesting the closure of two branch offices, and the conversion of one branch office into an APL due to declining branch office transactions.

The cost category for customer contact center operations are for approximately 164 energy services specialists who respond to customer inquiries by telephone, email, online chat, or written correspondence. For TY 2016, SDG&E is requesting $8.813 million, which is a reduction from its 2013 adjusted-recorded amount of $9.188 million. The lower cost is due to an overall reduction of 3.2 FTEs.

The customer contact support category are for resource planning and scheduling, technology support, policy and procedures support, planning and analysis functions, clerical support, training, and quality assurance. For TY 2016, SDG&E is requesting $2.395 million which is an increase from its 2013 adjusted-recorded cost of $2.322 million.

The cost category for other office includes the expenses associated with the vice president of customer services, and a business planning and budget project manager. These two positions provide leadership, guidance and support for customer service activities. SDG&E is requesting $0.871 million which is the same amount as its 2013 adjusted-recorded expenses.

6.8.1.2.2. Non-Shared Customer-Shared Information O&M Costs

The second cost component of customer service operations, information, and technologies is the non-shared customer service information activities. As described in Exhibit 101, these activities are composed of the following four work categories: residential customer services; commercial and industrial services; communications, research and web; and customer programs and projects. The total amount requested for customer service information is $30.126 million. This is an increase over SDG&E's 2013 adjusted-recorded expenses of $21.542 million.

The cost category of residential customer services is for activities that deliver and manage services and programs to residential customers. As described in Exhibit 101, these various activities include: regulatory and reporting support for the California Alternate Rates for Energy (CARE) program, and the medical baseline program; customer assistance for natural gas appliance testing, public safety outreach, and outreach education about plug-in electric vehicles and rate reform. SDG&E requests $6.607 million for this cost category, which is an increase over its 2013 adjusted-recorded costs of $5.576 million.

The cost category for commercial and industrial services provides services to small, medium and large business customers. These services include information about billing-related questions, programs and services, and educating these customers about rate and service options, and energy issues that affect their businesses. SDG&E is requesting $5.789 million, which is an increase from its 2013 adjusted-recorded costs of $5.305 million.

The communications, research and web cost category address activities in six primary activities: (1) mass communications to customers about various utility-related issues, including safety and outage preparedness; (2) website management of SDG&E's website; (3) collateral design and production of outreach materials; (4) customer research into quality of service transactions, anticipating customer information and service needs and preferences, and supporting the development of new customer service options; (5) social media engagement using social media channels; (6) the development and management of mobile applications for billing, and energy-related issues. For TY 2016, SDG&E is requesting $14.287 million, which is an increase over its 2013 adjusted-recorded costs of $7.940 million. This increase is driven by additional non-labor costs, and nine new FTEs.

The work category of customer programs and projects is primarily responsible for administering the demand response reliability programs. This unit also acquires customer information for databases, demographics and cost studies. For TY 2016, SDG&E is requesting $3.443 million for this work category, which is higher than its 2013 adjusted-recorded costs of $2.721 million. The increase is due to the addition of 5.2 FTEs and $0.215 million in non-labor costs.

6.8.1.2.3. Shared Customer Service Operations O&M Costs

The third cost component of customer service operations, information, and technologies is the shared customer service operations. These costs are composed of customer service strategies, business planning and budgets customer service, and the customer contact center strategy and analysis manager.

SDG&E is requesting a total of $376,000, which is the same as its 2013 adjusted-recorded cost.

6.8.1.2.4. Shared Customer Service Operations, Information, Technologies O&M Costs

The fourth cost component of customer service operations, information, and technologies is activities for non-shared customer service technologies, policies, and solutions. These activities cover planning and development, and the low emissions vehicle program. The planning and development shared service group provides analytical and execution support for initiatives in operational excellence, development and deployment of clean energy solutions for customers, advocacy for policies and regulations that support ratepayer interests and advance Commission policy, and maintaining a properly skilled workforce. The low emissions vehicle program shared service cost center supports account management, customer information, education, and training for SDG&E's nature gas vehicle program. SDG&E is forecasting $603,000 for these non-shared customer service technologies, policies, and solutions shared services. This is a slight increase over its 2013 adjusted-recorded cost of $600,000.

6.8.1.3. Positions of the Parties

6.8.1.3.1. ORA

ORA recommends a total O&M amount $78.526 million for the customer services line item shown at line 11 of SDG&E's summary of earnings tables. This amount of $78.526 million is composed of ORA's recommendation of $20.577 million for customer services field, and $57.949 million for customer service operations, information, and technologies.

For the customer services field costs, ORA recommends the amount of $20.577 million for TY 2016. ORA's amount is less than SDG&E's recommended amount due to ORA's use of 2014 adjusted-recorded costs.

For the total costs associated with the customer service operations, information, and technologies, ORA recommends the amount of $57.949 million. ORA's recommended amount of $57.949 million is composed of the following: (1) ORA's agreement with SDG&E's shared cost amount of $0.979 million; and (2) ORA's non-shared customer service operations, information, and technologies amount of $56.970 million.

As explained in ORA's Exhibit 353, its non-shared amount of $56.970 million for customer service operations, information, and technologies, is composed of two cost components: customer service operations; and customer service information. For customer service operations, ORA recommends $35.142 million. For customer service information, ORA recommends $21.828 million.

ORA's customer service operations amount of $35.142 million is composed of ten cost categories. In Exhibit 353 at pages 15-16, ORA accepts SDG&E's TY 2016 forecast for the following: meter reading of zero; credit and collection of $2.848 million; remittance processing of $0.875 million; postage of $4.333 million; branch offices of $1.734 million; customer contact center support of $2.395 million; and other office of $0.871 million. However, for the reasons stated in Exhibit 353, ORA recommends reductions in O&M costs for the following cost categories in customer service operations: reduce advanced metering to $8.135 million; reduce billing to $5.210 million; and reduce customer contact center operations to $8.741 million.

ORA also recommends that SDG&E's request to close two branch offices, and the conversion of one branch office into an authorized payment location, be denied. ORA contends that customers who use the offices that SDG&E plans to close are low income with limited resources, and will incur extra expense and time if they have to go to another branch office or authorized payment location to pay their bill. In addition, these customers may not have bank accounts to pay their bills on line or on a mobile phone. ORA also points out that the payments at branch offices post immediately to customer accounts, which is important when a customer faces disconnection.

For the cost component of customer service information, ORA's recommended amount of $21.828 million is composed for four cost activities. For the reasons stated in Exhibit 353, ORA recommends the following O&M amounts, which are lower than SDG&E's recommendations, for the following cost activities: $5.576 million for residential customer services; $5.305 million for the commercial and industrial services; $8.093 million for communications, research and web; and $2.854 million for customer programs and projects.

6.8.1.3.2. UCAN

In Exhibit 347, UCAN objects to the proposed closure of SDG&E's two branch offices and the conversion of one branch office to an authorized payment location. UCAN contends that "It is essential to provide opportunities for cash payment transactions and non-payment services throughout SDG&E's service territory for all customers and especially for low-income customers who may have reduced access to Internet and mobile payment methods and reduced mobility to travel to alternate locations." (Exhibit 347 at 86.) UCAN points out that the authorized payment locations do not provide the same level of service as branch offices.

UCAN also recommends that SDG&E use the same methodology that SoCalGas used to estimate the work activity related to seasonal on and seasonal off work orders. UCAN contends that because of a declining trend in these work orders due to a decline in pilot relights, that SDG&E's use of a five year average does not reflect this declining trend.

6.8.1.3.3. SDCAN

SDCAN contends in Exhibit 319 that SDG&E should provide more internet-based services. Although SDG&E has made a number of web-based services available, SDCAN contends that SDG&E's GRC application does not reflect the efficiencies created by these web-based services. SDCAN also contends that SDG&E did not describe in its GRC application the cost effectiveness of, and the savings associated, with using its web-based services.

SDCAN expressed concern about the customer service guarantee program, and the growing number of appointments that were missed by SDG&E in fulfilling work orders, and the credits given to customers because of the missed appointments. Given the technological and communication improvements, SDCAN contends that the number of missed appointments and credits should be dropping. SDCAN recommends that half of the cost of this service guarantee program should be borne by shareholders until SDG&E demonstrates in its next GRC that the number of missed appointments has dropped. If SDG&E provides evidence of such a reduction, then it might be appropriate for ratepayers to fully fund this program again.

SDCAN also recommends that a 10% reduction for "imputed efficiency," as applied by D.13-05-010, should also apply to SDG&E's proposed costs for its customer contact center operations, and its customer contact center support.

6.8.1.3.4. TURN

In Exhibit 400, TURN recommends that the cost of tickets to sporting and cultural events be removed from SDG&E's O&M costs. TURN contends that such costs be removed because they are not necessary to provide utility service. In the customer service testimony in SDG&E's Exhibits 86 and 101, TURN recommends that $4963 be removed.

TURN also recommends that the cost of clothing and other gear containing SDG&E's name and logo (excluding utility uniforms, hard hats, etc.) be removed from SDG&E's O&M costs. TURN contends that these kinds of items are "largely promotional and image-building (giveaways and other materials) and should not be paid for by ratepayers." (Exhibit 400 at 47.) TURN recommends that in the customer service testimony in SDG&E's Exhibits 86 and 101 that $18,556 be removed.

6.8.1.3.5. Joint Minority Parties

The Joint Minority Parties did not object to SDG&E's forecast of expenses under the customer services cost category. However, the Joint Minority Parties recommend that at least 5% of any rate increase be allocated for marketing, outreach, and education on key issues affecting utility customers, and those efforts be focused on those who are most affected by the rate increases.

6.8.1.3.6. SDG&E

SDG&E responded to the points raised by ORA and the other parties in Exhibits 88 and 104.

In response to the proposed adjustments to the cost categories in customer services field, SDG&E contends that ORA's use of the 2014 costs should be rejected. SDG&E contends that its "costs are impacted by a number of variables, including work order volumes, which fluctuate from year to year for most order types, and other variables." (Exhibit 88 at 5.) SDG&E also contends that its forecasting model accounts includes the variables which impact customer services field costs, but ORA's use of the 2014 costs as the base ignores those variables.

UCAN recommended that SDG&E use the same forecast methodology that SoCalGas uses to estimate the activity for seasonal on and seasonal off work orders. SDG&E contends that the historical patterns, including weather and appliance choices, for the two utilities are different, and that SoCalGas' methodology would not be appropriate for SDG&E.

Regarding SDCAN's recommendation, SDG&E states that SDCAN's assertions are not supported by the evidence. SDG&E contends that the missed appointments comprise less than half a percent of total orders scheduled, and that the appointments were missed because there was an increase in the number of Priority 1 emergency orders during the same time period. SDG&E also contends it has already made improvements in technology and efficiency.

Regarding TURN's recommendations to reduce the costs in customer services, SDG&E contends that it provides promotional materials at conferences, seminars, and community events to promote messages such as safety and energy conservation. With respect to the sports and cultural tickets, SDG&E contends that these expenses are proper business expenses to develop and maintain customer relationships, and to recognize and reward employees for extraordinary work.

SDG&E also responded to the other parties' proposed adjustments to the cost categories for customer service operations, information, and technologies. We summarize some of the points that SDG&E raised in Exhibit 104.

SDG&E contends that ORA's recommended reductions to the cost categories for customer service operations, information, and technologies, would effectively eliminate all of SDG&E's requested increase for TY 2016, and that ORA's recommendation would be below SDG&E's 2013 adjusted-recorded costs.

For ORA's recommendation of $8.135 million for the cost associated with advanced metering operations, SDG&E contends that ORA's methodology fails to incorporate the impact of advanced metering operations on order volumes and activity levels. SDG&E contends that advanced metering is still in the early part of its lifecycle, and historical data about the effect of smart meters on order volumes and activity levels are limited. For that reason, SDG&E contends that the zero based forecast method is appropriate for the labor costs, and 2013 is appropriate for non-labor costs.

Regarding ORA's claim that SDG&E already received funding for FTEs in its 2012 GRC, SDG&E contends that the funds had to be reallocated to meet higher priority needs. SDG&E further contends that ORA's recommended amount for advanced metering operations does not recognize that changes in business priorities can cause expenses to shift between workgroups.

With respect to ORA's reduction for billing activity, SDG&E contends that the funding for new FTEs for net metering activities is incremental, and is needed because of the increase in the number of accounts that use interval data and time-of-use rate structures.

With respect to the closure of branch offices, SDG&E contends that the arguments of ORA and UCAN for keeping the three branch offices open are flawed. SDG&E contends that the number of in-person payments has declined largely due to self-service options. SDG&E also notes that the in-person payments at the authorized payment locations that are located within a five-mile radius of the three branch offices it proposes to close have increased. SDG&E also contends that the three branch offices it plans to close (downtown, National City, and Oceanside) have the lowest volume of payments out of the seven branch offices and have been experiencing a long term trend in declining payment transactions, and have the highest cost per transaction for branch offices. SDG&E also contends that customers will not be inconvenienced by the closure of these three branch offices because there are authorized payment locations located within two miles of each of those three offices.

For customer contact center operations, ORA recommended the removal of $72,000 requested for costs associated with the CARE program. ORA contends that funding for this should occur in a different application. In Exhibit 104, SDG&E disagrees with ORA's recommendation to remove the CARE enrollment costs. SDG&E notes that it made a concurrent request in the low income proceeding to fund the CARE enrollment costs. If a decision in the low income proceeding authorizes funding of those costs, SDG&E would make an adjustment in this TY 2016 GRC proceeding.

In Exhibit 104, SDG&E responded to ORA's proposed reductions to the customer service information activities that are part of the customer service operations, information, and technologies. SDG&E's reasoning as to why ORA's proposed reductions should be disregarded is similar to the reasons that SDG&E provided earlier. SDG&E contends that ORA's use of 2014 adjusted-recorded costs should be ignored because it ignores several factors that affect SDG&E's recommended amount, as described in Exhibit 104, and that ORA selectively applies this method only to certain workgroups.

On ORA's proposed reduction to residential customer services expenses, which is a cost activity under customer service information, SDG&E disagrees with ORA's analysis that the costs that SDG&E is requesting for TY 2016 are already embedded in the base year 2013 expenses.

Similarly, SDG&E contends that for commercial and industrial services, ORA's analysis ignores the incremental activities projected for TY 2016.

For ORA's proposed reduction to communications, research and web, SDG&E claims that ORA acknowledged the increase in activities in this workgroup, but ORA disregarded these activities as being routine and ongoing for which no incremental increase was needed. SDG&E contends that the amount being requested for TY 2016 is justified by proposed new activities as described in Exhibit 104.

For the cost activity of customer programs and projects, SDG&E contends that ORA's proposed reduction ignores the incremental activities which merit additional funding.

On SDCAN's recommendations and observations regarding SDG&E's use of the internet to develop more services for its customers, and that greater operational efficiencies have not been reflected in SDG&E's forecast of costs, SDG&E responded to those issues in Exhibit 104. SDG&E also notes that it provided information about its internet-based presence and social media activities in Appendix A of Exhibit 101.

SDG&E also notes in Exhibit 104, that none of the parties take issue with SDG&E's proposed uncollectible rate of 0.174%, and that ORA explicitly adopts that rate.

With respect to the Joint Minority Parties' recommendation to spend monies on outreach and education, SDG&E contends that the recommendation is not supported by any evidence. In the event the Commission wants to consider

Joint Minority Parties' recommendation, SDG&E contends that such a recommendation should occur in the Low Income Energy Efficiency proceeding.

6.8.1.4. Settlement Agreements

6.8.1.4.1. Attachment 1 Settlement Agreement

In the SDG&E Settlement Comparison Exhibit at 333, the settling parties agree to a total amount of $85.448 million for customer services. At page 10 of the SDG&E Settlement Comparison Exhibit, the settling parties agree to certain cost sub-components of these customer services costs, including the following: the parties stipulate to the SDG&E forecast of $22.135 million of customer service field expenses; the parties stipulate to a compromise forecast of $62.333 million for customer service office operations, information, and technologies; and under the cost category for customer service office operations, information, and technologies, the parties agree to certain non-shared customer service operations expenses, and to certain non-shared customer service information expenses.

6.8.1.4.2. Attachment 5 Settlement Agreement

With respect to the proposed closure of three branch offices, SDG&E, SoCalGas, TURN and UCAN entered into a separate settlement agreement (Attachment 5) of the SDG&E Settlement Motion. As part of agreements in Attachment 5, the above parties agreed that SDG&E may file a separate application to seek closure of any currently existing branch offices during the 2016 GRC cycle.

None of the parties to these proceedings have opposed that portion of the Attachment 5 settlement agreement.

6.8.1.5. Discussion

After careful review and examination of the testimonies and other evidence presented by the parties, and careful consideration of the settlement agreement in Attachment 1 of the SDG&E Settlement Motion, the agreed upon amounts of $85.448 million for all of the customer services O&M costs is reasonable and supported by the evidence. In addition, the sub-components of the $85.448 million, as agreed to in the SDG&E Settlement Comparison Exhibit at 10, are also reasonable and supported by the evidence. In some instances, the settling parties agreed to SDG&E's recommended amounts, while in others the settling parties agreed to ORA's recommended amounts. In other instances, all of the parties agreed to stipulated amounts. All of these agreed upon amounts are supported by the evidence developed in these proceedings.

Accordingly, the agreed upon amount of $85.448 million for customer services, and all of the sub-components of that amount (as shown in the SDG&E Settlement Comparison Exhibit at 10), should be adopted.

Regarding SDG&E's proposal to close two branch offices and convert a third into an authorized payment location, that issue is addressed as part of the Attachment 5 settlement agreement between SDG&E, SoCalGas, TURN and UCAN. Those settling parties have agreed that SDG&E can file a separate application to seek the closure of any existing branch offices during SDG&E's TY 2016 GRC cycle. That portion of the Attachment 5 settlement agreement to SDG&E's settlement motion, is reasonable and should be adopted. As discussed in the summary section of this decision, we conclude that all of the other agreements reached in the Attachment 5 Settlement Agreement are reasonable and should be adopted. As a result, SDG&E's request in its GRC application regarding the downtown, National City, and Oceanside branch offices is denied without prejudice, and in accordance with the Attachment 5 Settlement Agreement, SDG&E may file a separate application to seek closure of these branch offices during this TY 2016 GRC cycle.

6.8.1.6. Capital Expenditures for Customer Services

For the capital expenditures related to the customer services for SDG&E, the business rationale for these expenditures are described in Exhibits 86 and 101. (See Exhibit 86 at 22; Exhibit 101 at 120.) However, the funding requests for those capital expenditures are discussed in the IT section below.

6.9. Information Technology (IT)

The IT division is responsible for a majority of the technology-related services such as supporting applications, hardware and software, and providing cybersecurity. The IT division performs these activities on behalf of SDG&E, SoCalGas, and Sempra. The costs for the IT services and activities are allocated to these three business units.

Line 12 of SDG&E's summary of earnings tables reflect the O&M costs for IT for both its electric and gas operations.

6.9.1. IT O&M Costs

As described in Exhibit 153, SDG&E is requesting a total of $109.115 million in IT O&M costs for TY 2016. Of this amount, $80.375 million is for SDG&E's electric operations, while $28.380 million is for SDG&E's gas operations.

The costs for the IT O&M costs are either shared or non-shared. The non-shared costs are related to activities that are performed solely for the benefit of SDG&E, and are charged to SDG&E cost centers. Of the total O&M costs of $109.115 million, the IT non-shared O&M cost is $18.188 million. The shared costs represent activities not solely dedicated to SDG&E, but the costs reside in SDG&E cost centers. The total requested for the IT shared services O&M costs is $90.925 million.

The O&M costs are categorized into four subgroups: Applications; Information Security; Infrastructure; and IT Support.

According to SDG&E, the Applications category supports systems in "customer field operations, work order management, smart meter data management, customer billing, service order routing, scheduling and dispatching, revenue cycle processing, and customer assistance and customer contact functions…." (Exhibit 153 at 12.) For TY 2016, SDG&E is requesting $17.153 million in non-shared costs, which is an increase over the 2013 recorded amount of $12.479 million. For the shared costs, SDG&E is requesting $24.924 million for TY2016, which is higher than the 2013 recorded costs of $18.517 million.

The Information Security category consists of regulatory compliance activities specific to SDG&E. SDG&E is requesting $0.159 million for the non-shared O&M costs, which is equal to its 2013 recorded expenses. For the shared O&M costs for Information Security, SDG&E is requesting $5.610 million for TY 2016, which is higher than the 2013 recorded costs of $3.586 million. The increased funding is for increased costs of ongoing hardware and software maintenance, penetration testing assessments, costs for additional training, and product evaluations.

The IT Infrastructure category supports the design, operation, and implementation of SDG&E's computing infrastructure and includes both hardware and software. Hardware includes desktops, servers and storage systems while software includes operating systems and low-level software systems. SDG&E is requesting $0.224 million for the non-shared costs for TY 2016, which is equal to its 2013 recorded expenses. For the shared O&M costs for IT Infrastructure, SDG&E is requesting $55.048 million for TY 2016, which is higher than the 2013 recorded costs of $48.614 million. Over half of the requested increase is associated with hardware maintenance contracts for equipment coming off warranty. Additional costs are for network costs, maintenance activities and improved reliability and performance.

The Support category covers the costs related to SDG&E's business optimization program, which assists various business units within SDG&E in the identification and implementation of operating efficiencies. For TY 2016, SDG&E is requesting non-shared O&M costs of $0.652 million, which is less than the 2013 recorded expense of $1.069 million. For the shared O&M costs for Support, SDG&E is requesting $5.343 million, which is slightly higher than the 2013 recorded costs of $5.308 million.

6.9.1.1. Position of the Parties

As shown at line 12 of its combined summary of earnings table, and as described in Exhibit 385, ORA recommended IT O&M costs of $99.327 million. ORA's recommended O&M costs are lower than SDG&E due primarily to ORA's use of different methodologies for the forecasting of labor and non-labor costs, and reductions in certain areas due to ORA's belief that SDG&E failed to analyze or substantiate its need for more personnel.

SDG&E contends that ORA's methodology for determining the O&M costs is inconsistent, and that ORA did not take into consideration new IT expenditures.

In the SDG&E Settlement Comparison Exhibit at 10, the settling parties stipulated to a compromise forecast of $106.368 million for IT O&M costs,[48] which is $2.745 million less than SDG&E's requested amount of $109.113.

6.9.1.2. Discussion

Based on the testimony of SDG&E and ORA, and comparing their recommendations to the SDG&E Settlement Agreement in Attachment 1 of the SDG&E Settlement Motion, the agreed upon IT O&M costs of $106.368 million are reasonable. The reasonableness of this agreed upon amount is based on the different methodologies that SDG&E and ORA used, and SDG&E's justification for the new IT O&M activities. The agreed upon IT O&M amount of $106.368 million should be adopted.

6.9.2. IT Capital Expenditures

The SDG&E Settlement Agreement did not separate out the IT capital expenditures for SDG&E's electric and gas operations. (See SDG&E Settlement Comparison Exhibit at 10 and 318.) For that reason, we discuss the total capital expenditures for SDG&E's electric and gas operations.

In Exhibit 153, SDG&E recommended the following capital expenditures: 2014 – $94.274 million; 2015 - $62.084 million; 2016 - $35.388 million. These capital expenditure projects are sponsored by the customer service unit (see Exhibits 86 and 101), and by the IT division (see Exhibit 153).

ORA's recommendation for the 2014 capital expenditures is based on the actual recorded expenditures for 2014 of $88.635 million. ORA did not oppose SDG&E's forecast of capital expenditures for 2015 and 2016.

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[48] For the total IT O&M amount of $103.368 million, the settling parties stipulated to $40.568 million for labor costs, and $65.800 million for non-labor costs.

Prior to the filing of the SDG&E Settlement Motion, UCAN objected to the IT capital funding request for the Bill Redesign Project due to insufficient details regarding the breakdown of costs by activity.

In the SDG&E Settlement Comparison Exhibit at 10, the settling parties have agreed to the following capital expenditures: 2014 - $88.635 million; 2015 - $62.084 million; 2016 - $35.388 million.

Based on the testimony of SDG&E and ORA concerning the IT capital expenditures, a review of the Attachment 1 settlement agreement of the SDG&E Settlement Motion, and ORA's acceptance of SDG&E's forecasted amounts for 2015 and 2016, the following agreed upon amounts for the IT capital expenditures are reasonable, and should be adopted: 2014 - $88.635 million; 2015 - $62.084 million; 2016 - $35.388 million.

6.10. Support Services

6.10.1. O&M Costs

Line 13 of SDG&E's combined summary of earnings table, which appears in Attachment 1 of the SDG&E Settlement Motion, shows the O&M costs for the support services for SDG&E's electric and gas operations. The cost elements which make up the support services for SDG&E are composed of the following pieces of testimony: Exhibit 174 – environmental services; Exhibit 270 – real estate, land services and facilities; Exhibit 166 – fleet services; and Exhibit 131 – supply management and supplier diversity.

In its update testimony, SDG&E requested total combined O&M costs for support services of $105.627 million. This total amount is made up of the following: $9.133 million for environmental services; $39.824 million for real estate, land services and facilities; $41.086 million for fleet services; and

$15.584 million for supply management and supplier diversity. (See SDG&E Update Testimony, Table KN-38.)

A breakdown of all of the cost elements which make up the support services for the electric operations is shown in Table KN-39 of Exhibit 219 and in SDG&E's update testimony. SDG&E's updated request for support services O&M costs for its electric operations is $82.418 million.

The breakdown of all of the cost elements which make up the O&M costs for support services for SDG&E's gas operations is shown in Table KN-42 of Exhibit 219 and in SDG&E's update testimony. SDG&E's updated request for support services O&M costs for its gas operations is $23.209 million.

The SDG&E Settlement Motion does not break down how the agreed upon settlement amounts for the support services O&M costs for SDG&E's electric and gas operations were derived. Thus, for the support services category of O&M costs, we discuss the combined amounts for SDG&E's electric and gas operations.

In Exhibits 366 and 383, ORA recommended total combined O&M costs for support services of $96.600 million. This total of $96.600 million is made up of the following: $8.920 million for environmental services; $38.273 million for real estate, land services and facilities; $34.879 million for fleet services; and $14.522 million for supply management and supplier diversity. As described in Exhibit 383, ORA's recommendations are generally lower than SDG&E's requested amounts because of the different methodologies that ORA used.

In the Attachment 1 settlement agreement of the SDG&E Settlement Motion, the settling parties agree to a total of $102.961 million for the O&M costs for support services. In the SDG&E Settlement Comparison Exhibit at 10-11, the settling parties agree that this settlement amount is made up of the following:

$9.175 million for environmental services; $39.086 million for real estate, land services and facilities; $39.161 million for fleet services; and $15.543 million for supply management and supplier diversity.[49]

As shown at line 13 in the electric and gas summary of earnings tables in the Attachment 1 settlement agreement, the settling parties have agreed to the amount of $80.316 million for SDG&E's electric operations, and the amount of $22.645 million for its gas operations.

We have reviewed the testimony of SDG&E and ORA, and have compared their positions to the amounts agreed to in the Attachment 1 settlement agreement as described above. The agreed upon settlement amounts for SDG&E's O&M costs for support services, as reflected at various pages in the SDG&E Settlement Comparison Exhibit, are reasonable, and those settlement amounts should be adopted. (See SDG&E Settlement Motion, Attachment 1, at SDG&E Settlement Comparison Exhibit at pages 10-11, 328, 333, 334, 335, 338, and 339.)

6.10.2. Capital Expenditures

The only capital expenditures being requested under the category of support services are for real estate, land services and facilities as shown in Exhibits 270 and 383. In Exhibit 270, SDG&E requests the following capital expenditures that is to be performed by the real estate, land and facilities unit: 2014 - $19.460 million; 2015 - $38.452 million; and 2016 - $42.930 million.

The real estate, land services and facilities unit is responsible for the administration of real estate, facilities, and land services. This unit plans,

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[49] Due to rounding, these four amounts add up to $102.965 million, instead of $102.961 million.

acquires, builds, and maintains these real estate and facility assets to support SDG&E's electric and gas operations. The capital expenditures are for a variety of different capital projects, as summarized in Exhibit 270 at page 21, and more fully described at pages 22-33 of Exhibit 270.

ORA recommended in Exhibit 383 that the following capital expenditures be adopted for real estate, land services and facilities: 2014 - $21.017 million; 2015 - $29 million; and 2016 - $29 million. ORA's recommendation for 2014 reflects the 2014 actual recorded expenditures. ORA's recommendations for the 2015 and 2016 capital expenditures are lower because some of the projects had not yet been approved by SDG&E management.

In the SDG&E Settlement Comparison Exhibit at 11, the settling parties stipulate to the following capital expenditures for real estate, land services and facilities: 2014 - $21.017 million; 2015 - $33.112million; and 2016 - $42.930 million.

Based on a review of the testimony of SDG&E and ORA concerning the capital expenditures for the support services category, and comparing that to what the settling parties have agreed to in the SDG&E Settlement Motion, the following agreed upon capital expenditures are reasonable and should be adopted: 2014 - $21.017 million; 2015 - $33.112million; and 2016 - $42.930 million.

6.10.3. Attachment 3 Settlement Agreement

Most of the costs associated with the Attachment 3 Settlement Agreement pertain to leak detection, which is addressed in the category of costs for Support Services.

The Attachment 3 settlement agreement to the SDG&E Settlement Motion resolves the contested issues between EDF, SDG&E, and SoCalGas. In this settlement agreement, as referenced earlier, the three settling parties agree to issues pertaining to Methane Leakage Abatement that was addressed in SB 1371, and which is the subject of the ongoing R.15-01-008. The settling parties also agree that the NERBA should be adopted as a two-way balancing account with the Applicants' proposed changes.[50]

None of the parties to these proceedings have objected to the Attachment 3 Settlement Agreement.

Since the settlement terms in the Attachment 3 Settlement Agreement do not prejudge what the Commission is doing in other proceedings, agree to continue ongoing discussions and negotiations regarding the abatement of methane leaks, and provide support for seeking the recovery of costs which exceed the LDAR forecast through the NERBA, the Attachment 3 Settlement Agreement is reasonable and should be adopted.

6.10.4. Attachment 4 Settlement Agreement

The Attachment 4 Settlement Agreement to the Settlement Motions of SDG&E and SoCalGas resolve contested issues with the Joint Minority Parties. Since the majority of the issues in the Attachment 4 Settlement Agreement pertain to supplier diversity issues, and supplier diversity costs are part of the Support Services cost, this is an appropriate part of the decision to discuss this settlement.

As described earlier in the summaries of each of the settlement agreements, the Attachment 4 settlement agreement addresses the following topics: (1) annual meeting with the Applicants' Chief Executive Officers to discuss topics pertaining to supplier diversity, customer programs, work force

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50 In the Attachment 1 Settlement Agreement to the SDG&E Settlement Motion and to the SoCalGas Settlement Motion, EDF and the Applicants also agreed to a two-way balancing account for the NERBA.

demographics, and philanthropy; (2) the Applicants are to host an annual public forum, where representatives from the Joint Minority Parties will be invited to offer input on topics pertaining to supplier diversity, customer programs, environmental issues, and philanthropy; (3) various activities regarding supplier diversity; (4) efforts to employ diverse firms to conduct accounting reviews and audit not currently conducted by Deloitte and Touche, and for the Applicants to host an annual networking meeting with minority certified public accountant firms to discuss potential opportunities; (5) to have the Applicants encourage their large law firms to provide pro bono work, and for the Applicants to host an annual networking meeting with their law firms and the Joint Minority Parties to discuss opportunities for pro bono work; and (6) working with the Joint Minority Parties to discuss ways to increase the number of small businesses participating in the Supplier Diversity Program, and for the Applicants to commit to maintain or exceed its current efforts in the areas of technical assistance and capacity building for small minority owned businesses.

None of the parties have objected to the Attachment 4 Settlement Agreement.

The terms of the Attachment 4 Settlement Agreement seek to increase the visibility of the Joint Minority Parties to advocate on the behalf of underrepresented communities and small businesses, and to provide input on issues that affect the utilities and these communities. In doing so, this advocacy appears targeted at increasing the participation of underrepresented communities and small businesses in the various activities that the Applicants engage in on a day-to-basis, from participation in the Supplier Diversity Program in procuring supplies and services, and workforce hiring. Such activities are consistent with the intent of General Order 156 and Pub. Util. Code §§ 8281-8286 to encourage the participation of Women, Minority, Disabled Veteran, and Lesbian, Gay, Bisexual and Transgender Business Enterprises in the procurement of contracts from regulated utilities.

The settlement agreement also encourages the Applicants' large law firms to provide pro bono work, but the type of pro bono work is not specified. We clarify that this pro bono work must be related to utility issues since approval of the Attachment 4 Settlement Agreement is being sought in the context of the Applicants' GRC activities.

For the above reasons, the Attachment 4 Settlement Agreement is reasonable, and should be adopted.

6.11. Administrative and General (A&G)

6.11.1. Combined A&G Costs

Line 14 of SDG&E's combined summary of earnings table, which appears in the Attachment 1 settlement agreement of the SDG&E Settlement Motion, shows the combined administrative and general (A&G) costs for SDG&E's electric and gas operations.

In its update testimony, SDG&E requests a total combined A&G cost of $431.532 million. The cost elements which make up this amount are described in Exhibits 15, 121, 193, 210, 222, 259 and 280, and are composed of the following: $35.985 million for regulatory affairs, controller, finance, legal and external relations; $141.414 million for compensation, health, and welfare; $19.628 million for human resources, safety, disability, and workers' compensation; $9.550 million for pension and postretirement benefits other than pension; $64.200 million for corporate center-general administration; $111.512 million for corporate center-insurance; $2.965 for risk management and policy; and

$46.278 million for other. (See Table KN-43 in Exhibit 219 and SDG&E Update Testimony.)

A breakdown of all of the cost elements which make up the A&G costs for SDG&E's electric operations is shown in Table KN-44 of Exhibit 219 and SDG&E's Update Testimony. As shown at line 13 of SDG&E's electric summary of earnings table, SDG&E requests the updated amount of $346.516 million for SDG&E's electric operations A&G cost.

The breakdown of all of the cost elements which make up the A&G costs for SDG&E's gas operations is shown in Table KN-48 of Exhibit 219 and SDG&E's Update Testimony. As shown at line 13 of SDG&E's gas summary of earnings table, SDG&E requests the updated amount of $85.016 million for SDG&E's gas operations A&G cost.

The SDG&E Settlement Motion does not break down how the agreed upon settlement amounts for the A&G costs for SDG&E's electric and gas operations were derived. Thus, for the A&G costs, we discuss together the amounts for SDG&E's electric and gas operations.

In Exhibits 333, 366, 381, 387, 389, and 391, ORA recommended total combined O&M costs for A&G costs of $354.865 million. This total of $354.865 million is made up of the following: $35.123 million for regulatory affairs, controller, finance, legal and external relations; $90.043 million for compensation, health, and welfare; $18.468 million for human resources, safety, disability, and workers' compensation; $9.550 million for pension and postretirement benefits other than pension; $59.648 million for corporate center-general administration; $104.091 million for corporate center-insurance; $1.061 million for risk management and policy; and $36.881 million for other.

ORA's recommendations are generally lower than SDG&E's requested amounts because of the different staffing levels, assumptions, and methodologies that ORA used, as described in ORA's testimony.

The settling parties have agreed to a total amount of $388.342 million for the A&G cost. This $388.342 million is composed of the settlement amount of $313.829 million for SDG&E's electric operations, and $74.512 million for its gas operations.

As shown in the SDG&E Settlement Comparison Exhibit at 12-13, the cost elements which make up the agreed upon A&G settlement amount of $388.342 million include the following: Exhibit 259 – $35.970 million for regulatory affairs, controller, finance, legal and external relations; Exhibit 193 – $90.482 million for compensation, health, and welfare; Exhibit 121 – $19.606 million for human resources, safety, disability, and workers' compensation; Exhibit 280 – $16.104 million for pension and postretirement benefits other than pension; Exhibit 222 – $61.300 million for corporate center-general administration; Exhibit 210 – $110 million for corporate center-insurance; and Exhibit 15 – $2.500 million for risk management and policy. (See SDG&E Settlement Motion, Attachment 1, SDG&E Comparison Exhibit at 11-13, 321-323, 333-335, 339-340.)

In comparing the testimony of SDG&E to ORA's testimony, and reviewing the Attachment 1 settlement agreement in the SDG&E Settlement Motion, the agreed upon settlement amounts for the A&G costs, as reflected at various pages in the SDG&E Settlement Comparison Exhibit, are reasonable. The agreed upon combined settlement amount of $388.342 million for the A&G cost, and as agreed to at various pages of the SDG&E Settlement Comparison Exhibit, should be adopted but shall be adjusted by the bonus depreciation adjustment. This results in the amount of $387.760 million.

6.11.2. Attachment 2 Settlement Agreement

The FEA entered into a settlement agreement with SDG&E and SoCalGas that is reflected in the Attachment 2 Settlement Agreement to the SDG&E Settlement Motion, and to the SoCalGas Settlement Motion. As described earlier, these three settling parties have reached agreement on two pension balancing accounts, the PBA and the PBOPBA. Both the PBA and the PBOPBA are subject to a two-way balancing account. The three settling parties specifically agree that the Applicants will not include the income tax impacts into those two balancing accounts. As a result of FEA's agreement to sign the SDG&E Settlement Motion and the SoCalGas Settlement Motion requesting adoption of the Attachment 1 Settlement Agreement with ORA, the Attachment 2 Settlement Agreement does not modify the amount agreed to in the Attachment 1 Settlement Agreement for total compensation expenses for SDG&E and SoCalGas.

None of the parties have objected to the Attachment 2 Settlement Agreement.

The agreements reached in the Attachment 2 Settlement Agreement to the SDG&E Settlement Motion, and the SoCalGas Settlement Motion are reasonable, and should be adopted.

6.11.3. Incentive Compensation Policies

This section on Incentive Compensation Policies applies to both SDG&E and SoCalGas.

Compensation costs are included as part of the A&G costs. These compensation costs include variable pay, which is also referred to as the incentive compensation program (ICP). This variable pay, or what we refer to as "variable compensation," is in addition to the base pay that employees receive. According to SDG&E's witness in Exhibit 193 at 6, "Variable pay is an essential component of a competitive total compensation package for a number of reasons including: creating focus on desired results, improving performance and facilitating ideas and improvements." SDG&E goes on to state at 6-7 of Exhibit 193 that "The ICP places a portion of employee compensation at-risk, subject to achievement of the plan's performance measures, motivating employees to meet or exceed important customer service, safety, supplier diversity, reliability, financial, and project completion goals."[51]

In the SDG&E Settlement Comparison Exhibit at 12, the settling parties stipulate to a compromise forecast of $32 million for SDG&E's variable compensation. The stipulation, however, does not resolve any policy issues regarding variable compensation.

In the SoCalGas Settlement Comparison Exhibit at 10, the settling parties stipulate to a compromise forecast of $25 million for SoCalGas' variable compensation. The stipulation, however, does not resolve any policy issues regarding variable compensation.

The variable compensation of both SDG&E and SoCalGas are included as part of the compensation expense under the A&G expense.

On July 20, 2015, the Energy Division staff issued data requests to SDG&E and SoCalGas for information about its "at risk" compensation, and how that compensation may be related to safety metrics.[52] These data requests are

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[51] See Exhibit 191 at 6-7 for SoCalGas' description of the ICP.

[52] The staff data request also sought information regarding other subject areas. (See September 21, 2015 Assigned Commissioner's Ruling.)

consistent with the issue identified in the February 5, 2015 scoping ruling at 7 of whether the utilities' proposed risk management, safety culture, policies, and investments will result in the safe and reliable operations of the utilities' facilities and services. After SDG&E and SoCalGas submitted their responses, the assigned Commissioner issued a ruling on September 21, 2015 seeking comments on the data responses, and to any objections to including the data responses of SDG&E and SoCalGas in the evidentiary record. The data responses of SDG&E and SoCalGas were attached to the September 21, 2015 ruling, which were later admitted into evidence as Exhibit 415 by the May 9, 2016 ruling of the ALJs.

The data requests regarding compensation raise the issue of how safety-related factors are considered in determining the award of variable compensation to the non-represented employees and executives of SDG&E and SoCalGas. The responses of SDG&E and SoCalGas in turn raise the related issue of whether the variable compensation formula adequately promotes a safety culture, or unduly benefits shareholders with the simple metric of the companies' financial performance and earnings, and whether it creates a situation where the two interests are conflicting. More broadly, the data request responses offer a window into how each of the utilities and the Sempra Board of Directors (Board) signal their priorities to employees, and whether they are safety-focused or earnings-focused.

In response to the September 21, 2015 ruling, MGRA objected to a provision in SDG&E's ICP which allows the Compensation Committee of Sempra's Board to exercise its discretion in including up to 10% of the earnings impact of the wildfire litigation for ICP purposes. This could have the effect of increasing revenues or decreasing expenses for Sempra if SDG&E is successful in recovering the uninsured costs of wildfires from ratepayers.

MGRA contends that this type of incentive is contrary to ratepayer interests because it rewards SDG&E's employees for seeking to have ratepayers pay for the wildfire costs, even though SDG&E was at fault. MGRA is concerned that this ICP provision could incentivize SDG&E's employees to aggressively seek to recover from ratepayers the $379 million in uninsured losses that resulted from the 2007 fires started by SDG&E lines. MGRA contends that this type of incentive could also weaken safety concerns because SDG&E's employees are incented to have ratepayers pay for these costs.

We note that today's decision does not prejudge or address the merits of the issues being litigated in A.15-09-010. SDG&E is seeking to recover from ratepayers $379 million in costs that were recorded in its Wildfire Expense Memorandum Account that was established in response to the October 2007 wildfires in SDG&E's service territory in 2007. SDG&E incurred a total of $2.4 billion in costs and legal fees to resolve the third-party claims associated with those wildfires.

However, since this GRC is examining the costs associated with compensating SDG&E's employees over the TY 2016 GRC cycle, it is appropriate to review how the non-represented employees and executives at both SDG&E and SoCalGas are compensated under variable compensation.

We agree with MGRA that SDG&E should be prevented from compensating its employees, managers, and executives from variable compensation that is based on a recovery of monies from ratepayers for the wildfire costs that are being litigated before the Commission in A.15-09-010. In the case of these wildfire litigation costs, variable compensation should not be awarded to SDG&E's non-represented employees and executives when the award is tied to the recovery of the wildfire costs in A.15-09-010. This type of financial incentive encourages SDG&E to aggressively pursue recovery of uninsured losses from its ratepayers, which can create the perverse incentive of minimizing safety-focused incentives while benefitting employees and management by shifting the costs of unsafe incidents onto ratepayers and being rewarded for doing so. The ICP should incentivize safety, instead of allowing this type of recovery which shifts the costs and risks of unsafe incidents onto ratepayers.

Accordingly, SDG&E is prevented during the TY 2016 GRC cycle from awarding variable incentive compensation to its employees, managers, and executives that is tied to the success of having ratepayers pay for some or all of the 2007 wildfire costs that are being litigated in A.15-09-010.

This line of inquiry and action is not isolated to the Applicants. In the wake of the disaster at San Bruno, the Independent Review Panel investigating the performance of PG&E and the CPUC found that:

> In the gas transmission business, management made a faulty assumption. It did not make the connection among its high level goals, its enterprise risk management process, and the work that was actually going on in the company. We think that this failing is a product of the culture of the company – a culture whose rhetoric does not match its practices." (Report of the Independent Review Panel San Bruno Explosion, Revised Copy, June 24, 2011, at 16.)

The CPUC is currently conducting an investigation (Order Instituting Investigation 15-08-019) into the role of PG&E's board, executive governance, compensation, and the role of these high level activities at PG&E in producing a corporate culture that undercut safety in its operations. While we do not make the argument here that SDG&E, SoCalGas, or Sempra is culpable of actions or behavior that are the direct cause of any hazard or injury to the public or the environment, we do seek to prevent the adoption of incentives that may promote or induce bad corporate culture regarding safety.

Similarly, SDG&E and SoCalGas should not be allowed to award variable compensation in other similar kinds of situations resulting from an unsafe incident. For example, the Aliso Canyon leak in SoCalGas' service territory caused the displacement of hundreds of families living in the nearby area, leaked a large amount of methane into the atmosphere, and resulted in significant costs. To award variable compensation to non-represented employees and executives for performance related to underground gas storage facilities, without considering an offset for the problems and costs incurred as a result of the leak, would be contrary to the interests of SoCalGas' customers who fund the cost of the variable compensation. To do otherwise, would reward the non-represented employees and executives for unsafe incidents that have resulted because of the utilities' prior actions. The non-represented employees and executives at SDG&E and SoCalGas should not be rewarded from variable compensation for unsafe incidents.

Currently, the Commission's SED is investigating the causes of the well leakage at Aliso Canyon. Until that report is finished, it is premature for the Commission to open an Order Instituting Investigation into the causes of the Aliso Canyon leakage, whether past expenditures were appropriately spent to detect these kinds of problems, and whether SoCalGas' ratepayers should bear any responsibility for the various costs incurred as a result of the leakage at Aliso Canyon. Those are all issues that should be examined in a future proceeding.

Still, SoCalGas shall be prevented during the TY 2016 GRC cycle from awarding variable compensation to its non-represented employees and executives for its operations at its gas storage facilities or at the Aliso Canyon storage facility unless SoCalGas has taken into consideration the detrimental effects of the Aliso Canyon leak as a full or partial offset to such compensation. Such an offset will provide a check on any variable compensation that may be awarded based on the operational performance of SoCalGas' gas storage facilities, due to the detrimental effects of the Aliso Canyon leak.

Recently enacted legislation supports our review of compensation expense, and requires us to consider an additional dimension: executive compensation in light of events such as wildfires, the Aliso Canyon leak, and other incidents affecting the safe and reliable operation of utilities. Assembly Bill (AB) 1266 (Statutes of 2016, Chapter 599) added Public Utilities Code Section 706, which provides in part:

> (b) For a five-year period following a triggering event, no electrical corporation or gas corporation shall recover expenses for excess compensation from ratepayers unless the utility complies with the requirements of this section and obtains the approval of the commission pursuant to this section.

Pub. Util. Code § 706 defines both "excess compensation" and a "triggering event"[53] and mandates in subdivision (f) that the Commission, "In every decision on a general rate case, shall require all authorized executive

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53 Pub. Util. Code § 706(a)(1) provides: "'Excess compensation' means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation that is in excess of one million dollars ($1,000,000)."

Pub. Util. Code § 706(a)(2) provides: "A 'triggering event' occurs if, after January 1, 2013, an electric corporation or gas corporation violates a federal or state safety regulation with respect to the plant and facility of the utility and, as a proximate cause of that violation, ratepayers incur a financial responsibility in excess of five million dollars ($5,000,000)."

compensation to be placed in a balancing account, memorandum account, or other appropriate mechanism so that this section can be implemented without violating any prohibition on retroactive ratemaking."

Pursuant to Pub. Util. Code § 706(f) and the Commission's broad ratemaking and enforcement authorities, SDG&E and SoCalGas will be ordered to file advice letters establishing Executive Compensation Memorandum Accounts. The memorandum accounts should track all monies for the annual salaries, bonuses, benefits, and all other consideration of any value set aside to be paid to the officers of the utility which are authorized in this decision, and to track that against the salaries, bonuses, benefits, and all other consideration of any value, paid to its officers. The Tier 2 advice letters should also define "officers" of each company subject to Pub. Util. Code § 706, and the definitions and the scope of salaries, bonuses, benefits, and all other consideration of any value shall be subject to Commission approval.

Such memorandum accounts will allow the Commission review what was paid and awarded to an officer in the years after a triggering event, and to determine in a company's application if any monies paid should be refunded (or allowed to be recovered in rates).

The amounts for variable compensation of $32 million for SDG&E, and $25 million for SoCalGas is subject to the Pub. Util. Code § 706 memorandum accounts discussed above.

We are interested in furthering the Legislature's and the Commission's own focus on safety and governance. As we stated, the data request responses (Exhibit 415) offer a window into how SDG&E and SoCalGas and the Sempra Board signal their priorities to employees, whether the priorities are safety-focused or earnings-focused, and whether they are appropriately balanced.

Public Utilities Code Section 963(b)(3) declares:

> 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. (Emphasis added.) (SB 705 (2011, Leno).)

In addition, Pub. Util. Code § 706 ties safety-related incidents to excess compensation, and whether ratepayers should have to pay for that compensation.

One of the leading indicators of a safety culture is whether the governance of a company utilizes any compensation, benefits, or incentive to promote safety and hold employees accountable for the company's safety record. As a matter of law, the Commission and the gas utilities are charged with creating a "culture of safety that will minimize accidents, explosions, fires, and dangerous conditions…." (Pub. Util. Code § 961(e)). As a matter of policy, the Commission promotes safety cultures at all utilities, not just the gas utilities. Among other things, the Commission committed to "[holding] companies (and their extended contractors) accountable for safety of their facilities and practices," "[providing] clear guidance on expectations for safety management and outcomes," and "[promoting] a culture of safety vigilance by CPUC staff, and in the industries we regulate." (*Safety Policy Statement of the California Public Utilities Commission*, adopted July 10, 2014.)

The Commission will carry out these policies by requiring SDG&E and SoCalGas to include certain testimony in their next general rate case filings and by informing SDG&E, SoCalGas, and Sempra that their governance, safety record, and safety culture will inform our reasonableness review of their future general rate cases, including the entirety of their requests for any compensation or benefits expenses or indeed for any expenditure. Through these policies, the Commission is placing an emphasis on safety and risk-based decision making, as adopted in D.14-12-025.[54]

The S-MAP and the RAMP processes are not yet fully implemented, the Commission's consideration of SDG&E's Wildfire Expense Memorandum Account in A.15-09-010 is still pending, and as discussed later in this decision, nothing in this decision forecloses the Commission's ability to institute a formal investigation into the leak at the Aliso Canyon underground storage facility. Irrespective of any other pending or future proceeding, we place Sempra and SoCalGas on notice that we will scrutinize their management and governance that preceded, coincided with, and which followed the leak at the Aliso Canyon storage facility.

Insofar as Sempra and SoCalGas have any discretion to withhold, deny, or claw back compensation, bonuses, severances, or any other benefit relative to any aspect of the management, funding, operation,

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[54] In D.14-12-025, the Commission adopted the S-MAP, and the RAMP. The S-MAP is to examine the models that the energy utilities use to prioritize and mitigate risks, and to establish guidelines and standards for the use of these models. The S-MAP is underway in the consolidated proceedings of A.15-05-002, A.15-05-003, A.15-05-004, and A.15-05-005. The intent of the RAMP is to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks in the context of its GRC filing.

management, and oversight of Aliso Canyon, then Sempra and SoCalGas should exercise those rights consistent with Pub. Util. Code §§ 706 and 963(b)(3) and the state policy of placing the safety of the public and of employees as the top priority. We also put Sempra Energy and SoCalGas on notice that their (1) awarding of compensation, bonuses, severances, or any other benefit, and (2) decisions to refrain from or limit withholding or clawing back of compensation, bonuses, severances, or any benefit, that are inconsistent with Pub. Util. Code § 963(b)(3) will directly inform the Commission's reasonableness evaluation of its future general rate case requests.

Further, to assist the Commission and the parties to gain a better understanding of whether and how safety policies, practices and performance are considered in the total compensation that is paid to non-represented employees and executives, we will require SDG&E and SoCalGas to provide additional information as part of its next GRC filing. This information shall also include information about the governance and level of engagement by Sempra's Board in influencing the variable compensation programs of SDG&E and SoCalGas.

In view of all the above considerations, in their next GRC applications, SDG&E and SoCalGas are directed to provide testimony of the actions taken during the 2016-2018 GRC cycle, supported by relevant workpapers, data, company documents, and reports containing the following information:

1. Describe what Board committees (for example, compensation committee, safety committee, or other committees) at Sempra, and at SDG&E or SoCalGas, are responsible for determining

the guidelines for establishing any compensation, bonuses, severances, and benefits.

2. Describe what direction Sempra provides to SDG&E or SoCalGas in formulating their compensation, bonuses, severances, and benefits.

3. Describe the qualifications of the Board members at Sempra and at SDG&E or SoCalGas who are responsible for determining the guidelines for establishing compensation, bonuses, severances, and benefits, and what committees they sit on.

4. Describe the coordination, if any, between the different committees that are responsible for developing the guidelines for establishing compensation, bonuses, severances, and benefits, and the frequency that these committees meet.

5. Describe the performance metrics and the measures used to set compensation, bonuses, severances, and benefits for non-represented employees and executives, and how these are used to determine them.

6. If applicable, describe how the compensation structure: creates long term and sustainable value for the utility; incentivizes employees; makes executives and managers personally accountable for safety and operational risks; creates a safer working environment and utility system; results in a demonstrated improvement of the utility's processes, policies, and performance; discourages below standard performance, or actions that are contrary to the interests of the utility and the utility's customers; holds employees, managers, and executives accountable for failure to comply with management's guidance, policies and instructions, and for below standard performance.

7. Describe how engaged and effective Sempra's Board is on operations, performance metrics, and safety-related incidents, including: how often Sempra's Board requests reports and/or presentations from SDG&E or SoCalGas regarding safety incidents, the effectiveness of risk management plans, and the effectiveness of operational processes; what Sempra's Board

did or directed in response to these reports and/or presentations; and whether and how frequently Sempra's Board followed-up or sought updates on the reports, presentations, and the Board's actions and directions.

8. Describe how risk management information is used by Sempra, SDG&E and SoCalGas; how the utilities share this information with their employees; describe the type of training or education that employees receive about management of risks; describe what processes are in place, if any, that allows the employees in the field to provide feedback on the management of risks, and the reporting of unsafe practices or unsafe incidents.

During the TY 2016 GRC cycle, the assigned Commissioner's office may request the staff of SED or the Energy Division to issue data requests of SDG&E and SoCalGas to provide further information regarding the operations and policies of the utilities, and the interrelationship with Sempra.

All of the above information will provide the Commission with a better understanding of: how risks are assessed and managed, how safety and risks are considered in the awarding of any compensation, bonus, severance, or benefit.

6.12. Other Adjustments to Operations and Maintenance Expenses

As shown at lines 16 through 21 of SDG&E's combined summary of earnings table, the following six categories need to be taken into account in calculating the total O&M expenses: shared services adjustments; reassignments; FERC transmission costs; escalation; uncollectibles; and franchise fees. These six items are discussed below.

6.12.1. Shared Services Adjustments

Line 16 of SDG&E's combined summary of earnings tables shows the adjustment for shared services. This adjustment is for shared service activities that are performed by SDG&E for the benefit of: (1) SDG&E or SoCalGas; (2) Sempra Energy corporate center; and/or (3) any unregulated subsidiaries. According to SDG&E, the shared service cost that is incurred by one utility on behalf of another, are allocated and billed to those companies receiving that service.

In its update testimony, SDG&E originally calculated shared services adjustments of $91.061 million. This calculation is based on the shared services costs that the other SDG&E witnesses derived.

ORA's testimony in Exhibit 387 states that it does not oppose the Applicants' shared services billing process and allocation of shared services costs. However, ORA has calculated total shared services adjustments of $90.728 million based on the different costs that the various ORA witnesses derived.

As shown in the SDG&E Settlement Comparison Exhibit at 333-335 and 340, the settling parties have agreed to total shared services adjustments of $90.216 million. This agreed upon amount of $90.216 million is derived from the other agreed upon settlement costs that contained shared services costs. Based on our acceptance of the other agreed upon settlement amounts, as discussed above, the shared services adjustments of $90.216 million is reasonable and should be adopted.

6.12.2. Reassignments

Line 17 of the combined summary of earnings table shows the reassignments of cost. These reassignments are performed to recognize that some of the costs (certain O&M, A&G, and clearing expenses) are incurred in support of SDG&E's capital-related construction efforts. The costs that are reassigned to capital become part of the rate base.

In Exhibit 309 at page 6, SDG&E originally proposed that the total amount of $127.958 million be reassigned to capital.[55] As discussed in that exhibit, and as shown in SDG&E's electric summary of earnings and gas summary of earnings table, $94.497 million was assigned to electric distribution, $3.354 million was assigned to electric generation, and $30.107 million was assigned to SDG&E's gas operations.

In Exhibit 367, ORA recommends a total reassignments amount of $99.507 million. ORA's testimony states that it does not oppose SoCalGas' reassignments, but ORA has calculated a different reassignments amount based on the different costs that the various ORA witnesses derived.

As shown in the summary of earnings tables in the Attachment 1 settlement agreement, the settling parties have agreed to reassignments which total to $114.924 million ($88.022 million for electric operations, and $26.903 million for gas operations). This agreed upon amount of $114.924 million is derived from the other agreed upon settlement costs that addressed the reassignment of O&M costs to capital costs.

Based on our acceptance of the other agreed upon settlement amounts, as discussed above, the reassignments amount of $114.924 million is reasonable and should be adopted.

[55] In SDG&E's update testimony, SDG&E requests an updated reassignments amount of $127.510 million.

6.12.3. FERC Transmission Costs

Line 18 of the Combined Summary of Earnings table shows the costs that are allocated to SDG&E's electric transmission unit, which is subject to FERC jurisdiction. This cost is shown as a separate line item to show the removal of those FERC regulated costs from SDG&E's revenue requirement in this proceeding. In its update testimony, SDG&E requested that $60.446 million be removed.

ORA requested in Exhibit 367 that $51.245 million be removed for the FERC transmission costs. ORA's amount is lower than SDG&E's recommended amount because of the "summation of ORA's different expense and capital recommendations made by ORA's various witnesses." (Exhibit 367 at 4.)

In the SDG&E Settlement Agreement, the settlement parties have agreed that $55.666 million in FERC transmission costs be removed.

Based on the testimony of SDG&E and ORA, and a comparison to the agreed upon settlement for the exclusion of the FERC transmission costs, the agreed upon amount of $55.666 million is reasonable. However, due to the bonus depreciation adjustment, this cost is now $55.593 million, which is the amount that should be adopted.

6.12.4. Escalation

The escalation adjustment for SDG&E is shown at line 19 of its combined summary of earnings table. This escalation adjustment is to account for the effects of inflation on SDG&E's forecasted costs that are in 2013 nominal dollars, and to adjust them to TY 2016 nominal dollars. This escalation discussion is different from the discussion of the cost escalators for post-TY 2016, found later in this decision.

Originally, SDG&E's escalation adjustment used the cost escalators from the IHS Global Insight (Global Insight) 4th Quarter 2013 Power Planner Forecast that was released in February 2014, and proposed an escalation amount of $29.106 million.[56] According to SDG&E, these escalators are based on recorded utility cost data that the FERC has gathered, which are then converted into forecasts by Global Insight. The forecasts that SDG&E used are discussed in more detail in Exhibit 305.

In its update testimony, SDG&E updated its cost escalation using the indexes from 1st Quarter 2015 Power Planner Forecast of Global Insight. This update testimony results in an escalation adjustment of $22.245 million.

When ORA reviewed SDG&E's application, ORA relied on the 4th Quarter 2014 Power Planner Forecast to derive its escalation amount of $19.114 million.

In the SDG&E Settlement Comparison Exhibit at 13, the settling parties stipulate to adopting ORA's escalation forecasts from the RO model. The use of ORA's escalation forecasts results in an escalation amount of $21.172 million as shown in SDG&E's combined summary of earnings table.

Based on a review of the testimony of SDG&E and ORA, and the agreement to use ORA's escalation forecasts, the use of ORA's escalation forecasts is reasonable because it results in an amount that is more up to date than what SDG&E originally used. Accordingly, ORA's escalation factors should be adopted to derive the escalation amount.

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[56] Global Insight is an econometric forecasting firm, whose forecasts have been used in various regulatory proceedings.

6.12.5. Uncollectibles

Line 20 of SDG&E's combined summary of earnings table addresses the amount associated with uncollectibles. The uncollectibles amount reflects an adjustment to the revenue requirement for unpaid customer bills.

In Exhibit 101, SDG&E proposes that the current uncollectible rate of 0.174% remain unchanged. ORA does not oppose SDG&E's proposal to maintain the uncollectibles rate at 0.174%.

There is no language in the SDG&E Settlement Comparison Exhibit which specifies whether SDG&E's uncollectible rate is being agreed to by the settling parties. However, based on ORA's acceptance of the uncollectibles rate that SDG&E proposes to use, and comparing the uncollectibles amount of $3.114 million that appears under the Settlement column of SDG&E's combined summary of earnings table to the uncollectibles amount of $3.263 million that was generated as a result of SDG&E's update testimony, it appears that SDG&E's RO model applies SDG&E's 0.174% uncollectibles to the SDG&E Settlement Agreement to yield the settlement amount of $3.114 million.

Since the settling parties have agreed to a TY 2016 revenue requirement of $1.811 billion, it is reasonable to use the uncollectibles formula embedded in the RO model, as adjusted by the bonus depreciation adjustment, which results in an uncollectibles amount of $3.007 million, and that embedded formula should be adopted.

6.12.6. Franchise Fees

Line 21 of SDG&E's combined summary of earnings sets forth the amount for franchise fees. As described in Exhibit 247 at 27, the "Franchise fees are payments made to counties and incorporated cities pursuant to local ordinances granting a franchise to the company to place utility property in the public rights of way." These franchise fee payments are based on the gross receipts of the utility, and for SDG&E, are calculated using the "Broughton Act" formula, and the "Percent of Gross Receipts" formula. As of January 1, 2013, SDG&E had franchise fee agreements with 30 taxing jurisdictions.

SDG&E's franchise fee amount shown in its combined summary of earnings table in Exhibit 219 and SDG&E's update testimony uses a franchise fee factor of 3.4273% for SDG&E's electric operations, and 2.0727% for its gas operations. Using these factors, SDG&E's updated testimony resulted in a combined franchise fee amount of $59.965 million.

In ORA's testimony in Exhibit 394, ORA agrees with SDG&E's use of the franchise fee factor of 3.4273% for SDG&E's electric operations, and 2.0727% for its gas operations.

As shown in SDG&E's combined summary of earnings table in the Attachment 1 settlement agreement, the settling parties have agreed upon the franchise fees adjustment which results in the total amount of $57.215 million.

The text of the SDG&E Settlement Comparison Exhibit that is contained in Attachment 1 of the SDG&E Settlement Motion does not specify how the franchise fee amount of $57.215 million was derived. However, in SDG&E's electric summary of earnings table, and its gas summary of earnings table, the franchise fee percentages are shown under the description column for line 21. For the electric operations, a franchise fee factor of 3.4273% is shown. For SDG&E's gas operations, a franchise fee factor of 2.0727% is shown. Also, a comparison of the amounts that were recommended by SDG&E and ORA for the franchise fees suggests that the settlement agreement's RO model applied SDG&E's franchise fee factors of 3.4273% and 2.0727%.

Since the settling parties have agreed to a TY 2016 revenue requirement of $1.811 billion, and ORA does not oppose the use of SDG&E's franchise fee percentages, it is reasonable to use the franchise fee factors embedded in the RO model, as adjusted by the bonus depreciation adjustment, which results in a total franchise fees amount of $56.531 million. Those embedded franchise fee factors should be adopted for SDG&E in this TY 2016 GRC proceeding.

6.13. Other Components of the Revenue Requirement

As part of the formula for developing the revenue requirement, the additional capital-related costs of depreciation, taxes on income, and taxes other than on income, need to be accounted for.[57] These three cost elements are added to the total O&M costs, which results in the total operating expenses. Adding together the "total operating expenses" and the "return" on ratebase produces the overall revenue requirement. These capital-related costs will vary depending on the level of O&M costs and capital expenditures which are adopted by the Commission, and would have to be recalculated to account for the impact of such changes.

In the Attachment 1 settlement agreement of the SDG&E Settlement Motion, the settling parties do not mention the amounts agreed upon for depreciation and amortization, taxes on income, and taxes other than on income. Instead, the agreed upon amounts are shown in the summary of earnings tables in the Attachment 1 settlement agreement. In addition, those same amounts are

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[57] Franchise fees are included in the Applicants' testimony regarding taxes, and are sometimes referred to by the Applicants as taxes other than income. However, those franchise fees appear as a separate line item under O&M costs in the Applicants' summary of earnings table, and are therefore separately addressed in this decision.

listed at page 340 of the SDG&E Settlement Comparison Exhibit. We discuss these three components below.

6.13.1. Depreciation and Amortization

In its updated testimony, SDG&E requested $439.813 million for depreciation and amortization.[58] The derivation of SDG&E's depreciation and amortization expense, and its accumulated reserve, is shown in Exhibit 295. According to SDG&E, the "purpose of depreciation and amortization expense is to provide for recovery of the original cost of plant (less estimated net salvage) over the used and useful life of the property by means of an equitable plan of charges to operating expenses." (Exhibit 295 at iii.)

In Exhibit 393, ORA reviewed SDG&E's derivation of the depreciation and amortization expense, and depreciation reserve. ORA did not recommend any changes to SDG&E's depreciation parameters. As shown in the combined summary of earnings table in the Attachment 1 settlement agreement, ORA recommends $423.822 million in depreciation and amortization expense. This amount of $423.822 differs from SDG&E's original amount of $420.902 million because of the "difference in their respective capital expenditures forecasts for 2014-2016." (Exhibit 366 at 25.)

As reflected in the combined summary of earnings table in the Attachment 1 settlement agreement, the settling parties have agreed to a depreciation and amortization amount of $432.059 million ($374.980 million for electric operations, and $57.079 million for gas operations).

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[58] In Exhibit 295 at page 1, SDG&E originally requested a total of $420.902 million for the 2016 depreciation and amortization.

The agreed upon settlement amount of $432.059 million is reasonable, and should be adopted, as it reflects the changes made to the various capital expenditure forecasts that were agreed to by the settling parties in the Attachment 1 settlement agreement.

6.13.2. Income Taxes

6.13.2.1. Background

In this section of the decision, we address the income tax expense of SDG&E and SoCalGas. The issues pertaining to the income tax expense of both SDG&E and SoCalGas are the same.

Line 24 of the summary of earnings tables in the Attachment 1 Settlement Agreement of the SDG&E Settlement Motion reflects the income tax expense, which is composed of federal income tax, and the California Corporation Franchise Tax (CCFT). In SDG&E's update testimony, income taxes of $163.233 million were forecasted. The derivation of the income taxes for SDG&E is found in Exhibit 247, in which SDG&E originally forecasted $163.529 million.

In Exhibit 394, ORA agrees with SDG&E's use of the 35% rate for the federal income tax rate, and with SDG&E's use of the 8.84% rate for the CCFT. ORA's forecast of the income tax for TY 2016 amounts to $144.279 million. As ORA points out, its tax expense forecast is dependent on ORA's forecasts of the income, expenses, and plant balances.

In the Attachment 1 Settlement Agreement, the combined summary of earnings for SDG&E shows income taxes in the amount of $152.735 million. This amount reflects the other costs that the settling parties have agreed upon.[59]

[59] The income tax amount for each utility is calculated in the RO model based on the adopted levels of O&M expense and capital.

In SoCalGas' update testimony, income taxes of $109.240 million were forecasted, as shown at line 22 of SoCalGas' summary of earnings table. The derivation of the income taxes for SoCalGas is found in Exhibit 244, in which SoCalGas originally forecasted $109.946 million.

In Exhibit 394, ORA agrees with SoCalGas' use of the 35% rate for the federal income tax rate, and the 8.84% rate for the CCFT. ORA's forecast of the income tax for TY 2016 amounts to $103.560 million. ORA's tax expense forecast is dependent on ORA's forecasts of the income, expenses, and plant balances.

In the Attachment 1 Settlement Agreement of the SoCalGas Settlement Motion, the summary of earnings for SoCalGas shows income taxes in the amount of $104.839 million.

There are two income tax issues that are relevant to the GRC proceedings of SDG&E and SoCalGas. The first issue is the repairs deduction, and the second issue is bonus depreciation. These two issues arise because of the timing of when the Applicants elected to use the change in accounting method for the repairs deduction, and the extension of the bonus depreciation tax benefits. The timing of these two changes affect how they should be treated from a tax perspective, and from a regulatory accounting perspective.

With respect to the repairs deduction, we addressed a similar adjustment for SCE, under similar circumstances, in D.15-11-021.

6.13.2.1.1. Terminology

A brief description about some of the terminology used in this section is helpful.

For tax purposes, a corporation reports its "taxable income." Taxable income is reported differently from the corporation's "book income." The book income is what is used for utility regulatory rate making purposes.

To derive its taxable income, the Applicants state that they made several permitted adjustments and deductions under the Internal Revenue Code (IRC), to their book income in the form of Schedule M adjustments. As described in Exhibits 244 and 247, these adjustments and deductions included the repairs deduction, and bonus depreciation.

For federal tax reporting purposes, the differences between taxable income and book income are reconciled in the Schedule M attachment[60] to the federal Corporation Income Tax Return, Form 1120. According to the Applicants, "The Schedule M adjustment for the repairs deduction represents the difference between expenditures that are permitted to be deducted as repairs for tax purposes and those same expenditures that are required to be capitalized for financial reporting purposes." (Exhibit 244 at 11; Exhibit 247 at 14.)

Due to the differences in how income is reported for tax and book purposes, this also affects the depreciation used for tax and regulatory purposes. Tax depreciation refers to the depreciation method allowed by the taxing authority, which includes accelerated depreciation.

Depreciation to determine income tax expense for ratemaking purposes is based on book depreciation.

The Applicants contend that the Commission's longstanding ratemaking policy is to flow-through all income tax deductions, except when specifically required by law or authorized in a proceeding. The Applicants cite to D.04-02-063 at 96-97 to describe the difference between flow-through and normalized ratemaking for income taxes:

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[60] Depending on income and assets, a different Schedule M form (Schedule M-1, M-2, or M-3) may apply.

There are two methods to account for income tax expense for regulatory purposes. Under the flow-through method, the income tax expense recognized for regulatory purposes during a given period is equal to the taxes that are assessed and paid during the period. Under the normalization method, the income tax expense for a given period is based on the net income recognized for regulatory accounting purposes during the period, regardless of when taxes associated with the accounting income are actually paid. The flow-through method can be viewed as cash basis accounting, while the normalization method reflects accrual accounting.

We discuss the two tax issues below.

6.13.2.2. Repairs Deduction

6.13.2.2.1. Introduction

The repairs deduction involves IRC §§ 162 and 263, and the characterization and tax treatment of expenditures that are related to maintenance, repair, and improvement activities. IRC § 162 allows for the deduction of all ordinary and necessary business expenses, including the costs of certain supplies, repairs, and maintenance. IRC § 263 generally requires the capitalization of amounts paid to acquire, produce, or improve tangible property.

IRS Regulation § 1.167(a)-11(d)(2)(i)(a) states in part that:[61]

> In general … expenditures which substantially prolong the life of an asset, or are made to increase its value or adapt it to a different use are capital expenditures,… [and] it is subject to the allowance for depreciation. On the other hand, in general, expenditures which do not substantially prolong the life of an asset or materially increase its

[61] See 26 Code of Federal Regulations at 1007.

value or adapt it for a substantially different use may be deducted as an expense in the taxable year in which paid or incurred.

During the 2011 to 2012 timeframe, when the TY 2012 GRC applications of the Applicants were pending before the Commission, the IRS issued regulations and guidance on whether repairs should be expensed or capitalized. These regulations and Revenue Procedures are described later in this section of the decision.

In Exhibit 400, TURN questions the Applicants' implementation of the regulations addressing the repairs deduction, and the impact on ratepayers.

6.13.2.2.2. Repairs Deduction Is An Open Issue

On the repairs deduction issue, all of the settling parties to the SDG&E Settlement Motion and to the SoCalGas Settlement Motion request approval of the five settlement agreements attached to the two Settlement Motions. The settling parties agree that all five settlement agreements are "a complete and final resolution of all issues among them in this proceeding, with the exception of a tax issue raised by TURN which, as specified in the TURN/UCAN Settlement [Attachment 5 Settlement Agreement], is not covered by the settlements and will be the subject of separate briefing." (SDG&E Settlement Motion at 2; SoCalGas Settlement Motion at 2.)

The Attachment 5 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions specifically provide that "All issues associated with the income tax – repair issue will be litigated separately from this Settlement, based on the existing evidentiary record and briefs to be submitted by interested parties." The Attachment 5 Settlement Agreement was entered into by the Applicants, TURN and UCAN.

As a result of the settling parties' recognition that the Attachment 5 Settlement Agreement is to be litigated separately, the settling parties recognize that the outcome of the repairs deduction issue may alter the revenue requirement amount agreed to by the settling parties in the SDG&E Settlement Motion and the SoCalGas Settlement Motion.

6.13.2.2.3. Background of Repairs Deduction

In Internal Revenue Service (IRS) Revenue Procedure 2011-43, which was issued on August 19, 2011, the tangible property regulations were explained in the context of "when to claim repair deductions associated with electric transmission and distribution property." (Exhibit 247 at 14.) This Revenue Procedure was established to "minimize disputes regarding the deductibility or capitalization of expenditures to maintain, replace, or improve transmission and distribution property...." (Revenue Procedure 2011-43, § 2.02.) According to § 2.02 of this Revenue Procedure:

> [T]his revenue procedure provides a "transmission and distribution property safe harbor method of accounting" for determining the amount of expenditures required to be capitalized under § 263(a). This revenue procedure classifies transmission and distribution property as either linear property (for example, conductor, poles) or nonlinear property (for example, transformers, customer electric meters). For linear property, this revenue procedure defines the appropriate units of property and provides a simplified method of determining when the cost of replacing a portion of a unit of linear property must be capitalized. For non-linear property, this revenue procedure defines the appropriate units of property but does not provide a simplified method of determining when the cost of replacing a portion of a unit of non-linear property must be capitalized. Taxpayers must follow the principles of § 263(a) to determine whether the replacement of a portion of a non-linear unit of property is deductible or capitalizable.

SDG&E notes in Exhibit 247 at 14 that: "This safe harbor method, if elected, is applicable to all assets, including pre-1981 property that would otherwise qualify for the percentage repair allowance ('PRA') deduction permitted under [Regulation] § 1.167(a)-11(d)(2)." The PRA deduction was the method Sempra used to deduct repair expenses before Revenue Procedure 2011-043 was issued.

On December 27, 2011, in Treasury Decision (TD) 9564, the IRS issued its temporary tangible property regulations interpreting IRC §§ 162 and 163. (See 76 Federal Register 81060.) These temporary regulations provided guidance regarding the deduction and capitalization of expenditures related to tangible property, and specified when taxpayers must capitalize, and when they can deduct, their expenses. These temporary regulations were later replaced and finalized in TD 9636. (See 78 Federal Register 57686, amended July 21, 2014, 79 Federal Register 42189.)

With the issuance of Revenue Procedure 2011-43, and the temporary tangible property regulations, SDG&E considered whether it should change its accounting method with respect to repairs. SDG&E engaged an accounting firm to determine if a change in accounting method to expense repairs as permitted by the Revenue Procedure and temporary regulations would be advantageous. After the accounting firm completed its studies, SDG&E decided to change its accounting method, and obtained automatic consents from the IRS and the Franchise Tax Board (FTB) to change its method of accounting for the repair deductions associated with its transmission and distribution assets.

The change in the accounting method led to SDG&E making the change to its 2011 and 2012 tax returns. This change in accounting method allowed SDG&E to deduct its repairs on its electric transmission assets under a safe harbor method, and to deduct the repairs under the accounting method set forth in Revenue Procedure 2011-43, instead of using the PRA methodology. The election to use this new accounting method increased the deductions for repair expense, which in turn immediately reduced SDG&E's tax liability and resulted in tax savings that were flowed-through to its shareholders.

For its TY 2016 GRC forecast, SDG&E used "current federal and state tax laws enacted through the filing date of this testimony." (Exhibit 247 at 10.)

For SoCalGas, it followed the guidance set forth in Revenue Procedure 2012-19, which was issued on March 7, 2012.[62] The guidance in Revenue Procedure 2012-19 clarified and expanded the temporary tangible property regulations set forth in TD 9564. Section 1.162-4 of TD 9636 provides that amounts paid or incurred for repairs and maintenance are deductible if the amounts paid are not required to be capitalized. Section 1.263(a)-1 provides the general rules for capital expenditures. Section 1.263(a)-2 provides the rules for applying Section 263(a) to amounts paid or incurred for the acquisition or production of tangible property.

SoCalGas also engaged an accounting firm in 2012 to perform studies on whether it would be advantageous to change its accounting method as permitted by Revenue Procedure 2012-19. SoCalGas concluded that it did, and obtained automatic consents from the IRS and the FTB to change its method of accounting to begin deducting certain repairs that are capitalized for book purposes. SoCalGas made the change in accounting method to its 2012 tax returns. This

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[62] Revenue Procedure 2012-19 was later superceded by Revenue Procedure 2014-16 in TD 9636 (78 Federal Register 57686). In TD 9636, final tangible property regulations were adopted, which replaced and removed the temporary tangible property regulations in TD 9564.

allowed SoCalGas to begin deducting repairs on a facts and circumstances basis, rather than deducting repairs under the rules prescribed by the PRA method. This change in accounting method increased the repair deduction, which had the immediate effect of reducing SoCalGas' tax liability, which SoCalGas flowed-through to its shareholders.

SoCalGas states in Exhibit 244 at 11 that prior to the change in accounting method:

> … SoCalGas followed its book capitalization policy for tax purposes. Accordingly, if the books treated an expenditure as a repair expense, then tax followed book to deduct the expense. Similarly, if books treated an expenditure as capital, then tax followed book to capitalize the expense.

After the change in accounting method by SoCalGas, it began to deduct repairs as permitted by Revenue Procedure 2012-19, instead of following the book capitalization policy. SoCalGas states in Exhibit 244 at 12 that this change in the "method of accounting is applicable to all assets eligible for the repairs deduction, including pre-1981 property that would otherwise qualify for the [PRA] deduction…."

For its TY 2016 GRC forecast, SoCalGas calculated its income tax liability "using current federal and state tax laws enacted through the filing date of this testimony." (Exhibit 244 at 7.)

The Applicants argue that their elections to change the accounting method benefits ratepayer by decreasing income tax expense and the revenue requirement for this GRC cycle. The Applicants state in Exhibit 244 at 12, and in Exhibit 247 at 14:

> Consistent with the treatment of its PRA deduction in prior years, [SoCalGas/SDG&E] has flowed-through the tax benefits associated with its projected repairs deduction to ratepayers for TY 2016 for

> both federal and California purposes in accordance with D.93848. The repairs deduction that is flowed-through for TY 2016 is substantially larger than the PRA deduction from prior GRCs. The corresponding decrease to income tax expense and to the revenue requirement resulting from the repairs deduction is significantly larger than if [SoCalGas/SDG&E] had continued to deduct repairs under the PRA method.

6.13.2.2.4. Position of the Parties

6.13.2.2.4.1. TURN[63]

TURN contends that the Applicants' election to use, and to implement the repairs deduction, took place between rate case proceedings. As a result, the change in the method of accounting for repairs was not forecast in the Applicants' TY 2012 GRC proceedings. TURN asserts that as a result of the changes to their accounting methods, this method resulted in higher deductible repair expenses during 2011-2015, which resulted in income tax savings of about $262 million ($131 million for SoCalGas for 2012-2015, and $131.1 million for SDG&E for 2011-2015), which the Applicants flowed-through to the benefit of their shareholders.[64]

TURN asserts that due to the timing of the change in accounting methods for both utilities, ratepayers will end up paying an extra $194 million (net present value) in rates for the period from 2016-2042. This is due in part to the decrease

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63 TURN, UCAN, and SDCAN (TURN et al.) filed a joint opening brief and reply brief in support of TURN's position on the repairs deduction. Since the arguments raised in the briefs of TURN et al parallel the arguments that TURN raised, we do not provide a separate summary of the arguments that TURN et al. made.

64 The $262 million is based in part on the Applicants' forecasts of capital spending for 2014-2015, and would need to be adjusted if the Commission adopts a different capital spending forecast.

in the long-term tax depreciation deduction as a result of the repairs being deducted from taxes immediately rather than being capitalized.

TURN states in Exhibit 400 at 14:

> This is a zero sum tax-timing game. SDG&E and SoCalGas have proposed to accelerate and flow-through tax deductions in 2011-2015 that would otherwise have (1) offset book depreciation that will no longer be deductible, and (2) provided a rate base offset for normalization of accelerated tax depreciation which ratepayers would have otherwise received over the life of future assets. The benefit of this change is being given to shareholders between rate cases, while saddling ratepayers with future tax bills that are higher than they would have been had the Sempra Utilities simply done nothing. This is a case where the utility's management has pursued a tax strategy that enriches shareholders at the expense of ratepayers. If shareholders are going to win, as the Sempra Utilities propose, then of necessity, ratepayers must lose.
>
> The end result is that (unless the Commission stops it), the Sempra Utilities will have its cake (a tax break for its shareholders now) and eat it too (more revenues in rates in the future because it would be allowed to hand the ratepayers the bill to reimburse the utilities for the future taxes created by the timing difference).

TURN recommends "normalizing the 2011-2014 portion of the repair allowance deduction change for SDG&E (2012-2014 for SoCalGas, which started a year later), and to flow-through 2015 funds captured in memorandum accounts to ratepayers." (Exhibit 400 at 13.)[65] TURN contends that normalization would treat the associated book depreciation amounts as if they continued to be

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[65] On May 9, 2016, TURN's motion to set aside submission and to enter a late-submitted exhibit into the evidentiary record was granted. This late-submitted exhibit, which was admitted into evidence as Exhibit 416, is the workpaper showing the tax-related calculations of the TURN witness sponsoring the adjustment recommendation.

deductible, thus lowering the income tax expense forecasts included in the revenue requirement.[66]

This normalization treatment would increase the accumulated deferred income tax (ADIT) balances used to establish the authorized revenue requirement, which would offset the rate base offset over the next 25-30 years.[67] According to TURN, the additional ADIT amounts to $60 million for SoCalGas, and $26.5 million for SDG&E. The ADIT amounts would result in about a $7 million annual reduction in revenue requirement for SoCalGas' ratepayers, and an annual reduced revenue requirement for SDG&E's ratepayers of $3.1 million. This is in contrast to the $131 million benefit flowed-through to SoCalGas' shareholders for 2012-2015, and the $131.1 million benefit flowed-through to SDG&E's shareholders for 2011-2015. TURN contends that this will achieve an outcome approximating ratepayer indifference to the tax change that was put into effect by SDG&E in 2011, and by SoCalGas in 2012.

TURN contends that this normalization is necessary because as a result of the change in the Applicants' tax methods between rate cases, the Applicants "are attempting to flow-through tax reductions from the increased federal repair deduction money to shareholders." (Exhibit 400 at 15.) TURN asserts that since this "flow-through was not forecast in the previous rate case (and in fact changes to the repair deduction were never mentioned in the 2012 TY GRC), the

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[66] TURN notes that its normalization recommendation is similar to the method that PG&E proposed in its TY 2014 GRC in A.12-11-009. PG&E's proposed method would reflect the change in the accounting method in the first rate filing after it has received approval from the taxing authorities.

[67] Since the ADIT records the difference between book and taxable depreciation, the amount in the ADIT will be lower due to less depreciation being taken as a result of the immediate tax deduction from the repairs deduction.

shareholders are proposing in this rate case to keep all of the higher repair allowances that were flowed-through in 2011-2015." (Exhibit 400 at 15-16.)

TURN notes that had the Applicants "changed their calculation methods but temporarily normalized the results of the higher repair deduction for the years 2011-2015 until the 2016 TY rate case, the ratepayers would have been kept whole rather than face a bill for the tax timing difference for decades to come." (Exhibit 400 at 17.)

As for the flow-through of the 2015 funds recorded into the memorandum account, TURN contends the Commission should direct that the account balances in this memorandum account, as of the date of the GRC decision, should flow to ratepayers. TURN estimates that approximately $20 million would be flowed through to ratepayers for 2015. In the alternative, TURN proposes that the amounts recorded in the memorandum accounts be normalized.

TURN contends that its recommendations are warranted because the Applicants have been able to transfer a total of $262 million of federal ($225 million) and state ($37 million) income tax reductions to shareholders over the 2012-2015 period.[68] At the same time, ratepayers would be charged $492 million in higher rates from 2016-2042 in nominal dollars ($194 million net present value).[69] The $262 million in reduced income taxes is derived from the immediate savings of deducting a repair expense, as opposed to capitalizing the repair activity over a period of time.

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[68] See Table 7 in Exhibit 400 at 14.

[69] The $194 million is the sum of the amounts for SDG&E and SoCalGas as shown on line 5 of Table 9 in Exhibit 400 at 24. The $194 million in net present value was later revised to $184.545 million in Exhibit 416.

According to TURN, the $492 million in higher rates ($184.545 million net present value) is attributable to the following: the lower amount of depreciation that results from the immediate deduction for the repairs deduction; the decrease in the amount of depreciation results in a higher increase in the amount of taxes owed over the long term; due to the immediate deduction, ADIT is reduced which increases the rate base amount and leads to an increase of the revenue requirement; and the effect of IRC § 481(a) to normalize the out-of-period change.[70]

TURN contends that the Applicants did not take any steps to share some or all of the tax savings with ratepayers, even though there were several ways of doing so. TURN suggests that the Applicants should have done the following: (1) included the increased repairs deduction in the update testimony for the TY 2012 GRC proceeding;[71] (2) inform the Commission beforehand of the Applicants' change in accounting method, and seek authorization to establish a memorandum account to track the increased repairs deductions; and (3) seek Z-factor treatment for the repairs deduction. TURN contends that the Z-factor could have been used since the Z-factor is defined in SoCalGas' Preliminary Statement to include "Tax law changes by the federal government, the State

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70 IRC § 481(a) is a cumulative catch-up adjustment that reflects the tax difference between the old and new regulations as a result of the change in accounting method.

71 TURN notes in Exhibit 400 at 20 that had the Applicants forecast the $262 million in income tax savings and flowed this through in rates in 2012, the Applicants' ratepayers would have received about $442 million in lower rates in 2012-2014.

Franchise Tax Board, Board of Equalization, or any local jurisdiction having taxing authority." (Exhibit 400 at 19.)[72]

TURN contends that the Applicants' reduced tax expense from the change in accounting for the repairs deduction was not the product of improved or increased productivity, but rather a windfall opportunity that was made available by the IRS. For that reason, TURN contends that the Applicants' shareholders should not receive the benefits of the change in accounting method.

To prevent this type of situation from occurring in the future, TURN recommends that the Commission require any future voluntary tax changes made by SDG&E or SoCalGas to take effect in GRC test years unless arrangements are made to make ratepayers whole. TURN asserts this will avoid the problem of having ratepayers receive disproportionately fewer benefits while bearing disproportionately higher costs.

TURN notes that unlike the repairs deduction issue that was raised in SCE's GRC in A.13-11-003, this is the first time the Commission has been able to review the Applicants' actions, and how to treat those funds for ratemaking purposes.

TURN contends it is not proposing any kind of retroactive ratemaking because it is not proposing to adjust any authorized revenue requirements or rates in 2011-2014. Instead, TURN is "only proposing to change the ratemaking for 2011-2014 tax year repair allowances ***prospectively***, starting in TY 2016," and "proposing to flow-through to ratepayers the funds associated with tax year 2015 that are collected in the Memorandum Accounts authorized in 2015 for each of

[72] The same wording regarding the definition of the Z-factor also appears in Section IV of SDG&E's Preliminary Statement.

the Sempra Energy Utilities (although that money could also be normalized if the Commission chose to do that)." (Exhibit 400 at 27, original emphasis.)

6.13.2.2.4.2. Applicants

The Applicants contend that TURN's proposal to change the treatment of the repairs deduction has the effect of refunding amounts to ratepayers through a rate base adjustment, which the Applicants contend is retroactive ratemaking and thus is impermissible. The Applicants contend that the relief that TURN seeks is contrary to longstanding regulatory policy and precedent on flow-through taxes and future test year ratemaking, and amounts to retroactive ratemaking.

The Applicants contend that the change in the method of accounting, which reduces the Applicants' tax liability, benefits both shareholder and ratepayers. The Applicants contend that TURN's recommendation ignores the evidence that there will be substantial long term benefits to their customers in the form of net lower rates beginning in 2016, as compared to if the Applicants had not changed their method of accounting.

The Applicants contend that the benefit for SDG&E's ratepayers beginning in 2016 and onward is about $45 million annually in reduced revenue requirement in each and every year, net of the ratepayer costs as quantified by TURN. The Applicants contend that the ratepayer benefits associated with SDG&E's accounting method change is a flow-through forecasted repair deduction of more than $280 million for 2016-2018, which translates to an approximately $134 million reduction in the revenue requirement over that three-year period, or about $45 million per year. SDG&E also received an immediate increase in ADIT of $26.5 million in TY 2016 through the normalization required by the IRC § 481(a) adjustment. This $26.5 million offsets SDG&E's rate base by $26.5 million in TY 2016.

The Applicants contend that the benefit for SoCalGas' ratepayers beginning in 2016 and onward is about $50 million annually in reduced revenue requirement each and every year, net of the ratepayer costs as quantified by TURN. The Applicants contend that the ratepayer benefits associated with SoCalGas' accounting method change is a flow-through forecasted repair deduction of more than $273 million for 2016-2018, which translates to an approximately $155 million reduction in the revenue requirement over that three year period, or about $50 million per year. The ADIT for SoCalGas also increased by $60.5 million, which offsets SoCalGas' rate base by that amount in TY 2016.

The Applicants contend that this change in the accounting method will continue to provide increased tax benefits to ratepayers indefinitely. The Applicants contend that one can reasonably extrapolate benefits to SDG&E's ratepayers of about $1.125 billion in nominal dollars for 2019-2042 ($45 million annually multiplied by 25 years), and to SoCalGas' ratepayers of about $1.250 billion in nominal dollars for 2019-2042 ($50 million annually multiplied by 25 years). The Applicants contend that there is not a single year, or combination of years from 2011 through 2042 in which ratepayers are not better off as a result of the Applicants' election to change its accounting method for repairs.

The Applicants forecast that the election to change its method of accounting for repairs will flow-through to ratepayers in 2016-2018 an increase in tax deductions of more than $273 million for SoCalGas, and more than $280 million for SDG&E. This flow-through will result in a corresponding reduction over those three years to SoCalGas' revenue requirement of over $155 million, and to SDG&E's revenue requirement of over $134 million.

The Applicants also contend the change in accounting method benefits ratepayers over the long term due to lower income tax expenses from 2016 through 2042. The Applicants contend that both ratepayers and shareholders will receive more tax benefits from the cumulative effect of the change in accounting method, than if the Applicants had not elected to change their method of accounting.

The Applicants describe TURN's proposal as follows:

> TURN proposes to take the incremental increase in the repairs deduction resulting from[SoCalGas'/SDG&E's] change in accounting method for its 2011-2014 tax years, which [SoCalGas/SDG&E] had treated as a flow-through tax adjustment in those years, and normalize that total amount beginning in the 2016 Test Year. (Exhibits 246 and 249 at 7.)

The Applicants contend that their elections to change their method of accounting for the repairs deduction, "and the timing of those elections, were appropriate, fully supported by tax law and regulatory precedent, and do in fact provide ratepayers with a substantial benefit." (Exhibits 246 and 249 at 8.) The Applicants further contend that:

> A taxpayer is prudent to minimize its tax liability as permissible by law. For a regulated utility, resulting tax benefits can be flowed to ratepayers, shareholders, or both, depending on timing of events, the existence of sharing mechanisms, and compliance with longstanding ratemaking principles. The changes in tax guidance … drove [SoCalGas'/SDG&E's] deduction elections and the Commission's flow-through policy dictated the result. (Exhibits 246 and 249 at 8.)

The Applicants contend that they have acted within the Commission's rules, and proceeded appropriately and prudently with respect to researching and then making the method change. In the absence of any claim or evidence of wrongdoing or ratepayer harm, the Applicants contend it would be unjust to adopt a remedy that punishes the Applicants for following all of the rules.

The Applicants' arguments as to why TURN's proposal should be rejected, center around three arguments.

The first argument is that TURN's proposal conflicts with the Commission's policy and precedent on flow-through taxes. The Applicants contend that the deduction for repairs has been treated as a flow-through adjustment. According to the Applicants, TURN's proposal would reverse the flow-through treatment, and instead normalize the change in accounting method by calculating the incremental ADIT increase, and reducing the rate base with those deferred taxes for the next 25-30 years. The Applicants assert that this is contrary to the Commission's precedent and policy of treating expenses as a flow-through whenever possible, and would take away the shareholder benefit that have already been received. The Applicants further contend that there has been no authorization or legal requirement that the Applicants' repair cost expenses be normalized. Since precedent and policy require these expenses to be treated as flow-through items, the Applicants contend that normalization is not required under federal tax law.

TURN's proposal would also flow-through the amounts being tracked in the memorandum account in 2015. TURN estimates that under its proposal, approximately $20 million would be flowed-through to ratepayers for 2015.

The second argument that the Applicants make is that TURN's proposal conflicts with the Commission's longstanding policy that in between GRC cycles, the shareholders benefit when the Applicants can do something for less, and ratepayers ultimately benefit because such a productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. That is, the fundamental feature of forecasted ratemaking is that forecasted amounts are not adjusted to reflect actual results. The Applicants contend that TURN's proposal would do exactly that by reaching back into prior years, and re-characterizing flow-through repair deductions as normalized deductions beginning in 2015 or 2016.

The Applicants also note that in D.84-05-036 (15 CPUC2 42), the Commission recognized individual tax factors should not be isolated for the purpose of comparing estimated and recorded results, and that any prospective adjustment would have to take into consideration the overall effect of the differences for all components of the test year.

The third argument the Applicants make is that TURN's proposal leads to retroactive ratemaking. The Applicants contend that TURN's proposal essentially reaches back into prior years (2011-2015 for SDG&E, and 2012-2015 for SoCalGas), and reallocates to ratepayers the benefits received as a result of the accounting method change that SDG&E made pursuant to Revenue Procedure 2011-43, and that SoCalGas made pursuant to Revenue Procedure 2012-19. The Applicants contend that this amounts to impermissible retroactive ratemaking because TURN is proposing to reach back into a prior rate case period, calculating the future cost to ratepayers of an election taken during that past rate case period, and to recover that cost through offsets to the Applicants' rate base.

In deciding what constitutes retroactive ratemaking, the Applicants contend that the operative fact is whether this type of situation is a first time event. The Applicants contend that the deduction for repairs has been around for many years, and that the Commission has consistently treated a deduction for repairs as a flow-through. The Applicants contend that TURN's proposal amounts to retroactive ratemaking because it would impact the deductions for repairs that was included and considered in the TY 2012 GRC proceedings in prior GRC proceedings, and would be contrary to what the Commission has done in the past. The Applicants contend that TURN's proposal would effectively refund amounts to ratepayers that had been included in previously approved rates, and that such a decision that revises costs that formed the basis for prior rates is precisely the type of action that is prohibited by the retroactive ratemaking doctrine.

The Applicants also note that the January 15, 2015 ruling granting TURN's request for a memorandum account in these proceedings recognizes that the Commission needs to guard against retroactive ratemaking occurring before January 15, 2015.

The Applicants contend that TURN's proposal will open the door for circumventing the statutory prohibition in Pub. Util. Code § 728 against retroactive ratemaking to reach a desired result.[73] The applicants contend that if TURN's proposal is adopted, then virtually any adjustment that relates back to elections made in past years that are covered by prior rate cases, can avoid retroactive ratemaking by simply applying the adjustment prospectively. The Applicants contend that no party should be allowed to alter the treatment of

[73] Pub. Util. Code § 728 states in part: "Whenever the commission, after a hearing, finds that the rates or classifications, demanded, observed, charged, or collected by any public utility for or in connection with any service, product, or commodity, or the rules, practices, or contracts affecting such rates or classifications are insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force."

specific items from prior settled GRCs (and thus alter rates for those years) by merely reflecting a prior year adjustment in a future year and calling it prospective. Such a change would render retroactive ratemaking moot.

The Applicants further contend that the change in how the repairs are accounted for was not a change in law or a change in tax regulation. Instead, the revenue procedure is an administrative guidance document that allows a taxpayer to change from one acceptable method of accounting to another acceptable method. According to the Applicants, the only impact of this change in method was to provide additional certainty as to what qualifies as a repair under existing law, which had the result of increasing the amount of the repairs deduction over what it had been historically using the PRA method.

Regarding TURN's assertion that the Applicants were aware of Resolution L-411A, and should have requested a similar memorandum account, the Applicants contend that the resolution was limited to the impact of the tax change referenced in that resolution.

As for TURN's suggestion that the Applicants should have requested a Z-factor adjustment, the Applicants contend that the Z-factor adjustment was not an option because the change in accounting method failed to meet the necessary requirements for a Z-factor adjustment.

As for TURN's contention that the Applicants should have waited until 2016 to make the change in accounting, the Applicants contend that such a wait was unrealistic under the circumstances.

6.13.2.2.4.3. SCE

SCE supports the Applicants' position that TURN's proposed adjustment is prohibited by the retroactive ratemaking doctrine set forth in Pub. Util. Code § 728. SCE contends that the fundamental rule is that rates are prospective, and future rates may not be designed to recoup past losses. SCE contends that the rule against retroactive ratemaking is to protect customers from surcharges, and at other times, to protect utilities from refunds. The equity behind the prohibition against retroactive ratemaking is that it has steady application regardless of what party is seeking to reexamine the past.

SCE contends that the Applicant's 2012 revenue requirements, including regulatory income tax expenses, were determined under cost of service ratemaking and the Commission's procedures for processing GRCs. A change in IRS procedures subsequently led to the lowering of income taxes relative to the method underlying the TY 2012 GRC amounts.

As for TURN's argument that this is the first opportunity for the Commission to review this change in accounting method, SCE contends that this does not exempt TURN's proposal from violating the prohibition against retroactive ratemaking. TURN has not offered any authority in support of its "first opportunity to review" argument. SCE contends it is almost always the case that the amounts adopted for the test year differ from the amounts that are later recorded. It also fits the definition that retroactive ratemaking occurs when a utility is permitted to recover an additional charge for past losses, or when a utility is required to refund revenues collected pursuant to its lawfully established rates.

Regarding TURN's argument that the Applicants should have followed Resolution L-411A, SCE contends that the longstanding policy is to flow-through tax deductions unless otherwise required by law. SCE contends that since the repairs deduction are not subject to normalization, the Commission policy of allowing it to be flowed-through should be followed.

SCE contends that TURN's calculation of the amounts is distorted because TURN's numbers are based solely on the Applicants' 2011-2015 amounts. TURN's numbers ignore the ongoing benefits of the applicants, whereas the Applicants' numbers identified the ratepayer benefits starting in 2016, and will continue to provide increased tax benefits to ratepayers indefinitely.

SCE also contends that TURN's calculation is analytically inconsistent with how the Commission sets its forecast of the TY revenue requirement. SCE contends that the tax deductions do not exist in a vacuum, and that the repair deductions are tied to the amount of repair expenditures. SCE contends that the TY 2012 revenue requirement was based on estimated 2012 expenditures, expenses, and associated tax attributes, and that the attrition years were based on the escalation mechanism.

SCE also agrees with the Applicants that adopting TURN's proposal would risk a normalization violation. Since the deferred tax balances are subject to the normalization rules, a Commission order that violates the normalization rules would render the affected utility unable to claim accelerated depreciation.

Regarding the Z-factor, SCE contends that the Z-factor adjustment is not applicable because utility management exercised control over the change in tax method.

6.13.2.2.5. Discussion of Repairs Deduction

6.13.2.2.5.1. In General

As described earlier, this issue has arisen because of the Applicants' elections in 2011 and 2012 to follow the guidance set forth in Revenue Procedure 2011-43, and Revenue Procedure 2012-19. These two Revenue Procedures provided guidance regarding the deduction of ordinary and necessary business expenses as provided for in IRC § 162, and the capitalization of amounts paid to acquire, produce, or improve tangible property as provided for in IRC § 263. As a result of these Revenue Procedures, SDG&E implemented a change in accounting method for the deduction of repairs to its 2011 and 2012 income tax returns. SoCalGas implemented the change in accounting method to its 2012 income tax return.

In Exhibits 244 and 247, the Applicants described the adjustments they made to Schedule M to reflect the different in book income and taxable income. One of the adjustments that they made was for the repairs deduction. As a result of the Revenue Procedures referenced earlier, SDG&E and SoCalGas implemented the change in the method of accounting to begin deducting certain repair expenses that are capitalized for book purposes. According to the Applicants' testimony, this change in method applied to all assets, including pre-1981 property that would otherwise qualify for the PRA deduction.

Thus, for TY 2016, the Applicants use the repairs deduction method permitted by the Revenue Procedures instead of the PRA method. The Applicants also state that "Consistent with the treatment of its PRA deduction in prior years, [SDG&E/SoCalGas] has flowed-through the tax benefits associated with its projected repairs deduction to ratepayers for TY 2016 for both federal and California purposes in accordance with D.93848." (Exhibit 244 at 12; Exhibit 247 at 14.)

We recognize that the Applicants' elections of the repair expense tax deductions are beneficial to ratepayers. But the Applicants should have come forth to the Commission about their consideration of these elections when the Commission was reviewing the Applicants' 2012 GRC forecasts. Because the Applicants did not come forth about the tax savings that the Applicants realized during the 2012 GRC proceeding, the income tax expenses forecasted and approved in D.13-05-010 were higher than the Applicants knew they would incur in 2012-2015.

The Applicants do not dispute that they received a benefit of $262 million in savings from paying less income taxes due to the higher repairs deduction allowed by the change in accounting method. They explain that this is due to the historical flow-through of income taxes. Due to the historical treatment of the flow-through of income tax expense, and because this change occurred after the conclusion of evidentiary hearings in the Applicants' TY 2012 GRCs, the Applicants treated the 2011-2015 change in accounting method, and the tax savings resulting from that change, as a flow-through to their shareholders.

The Applicants' accounting changes resulted in an immediate tax savings benefit to the Applicants of $262 million over the 2011-2015 period, which the Applicants' witness agreed led to increased earnings for the utility. (See 21 R.T. 2426-2427.) Had this change in accounting method been considered as part of the Applicants' TY 2012 GRC proceedings when the Applicants knew they would elect the repairs deductions, and knew that a considerable amount of tax savings would result from these elections, the income tax savings would have flowed to ratepayers, instead of to shareholders. As a result, the Applicants' shareholders have received a benefit of $262 million due to the timing of the accounting change between rate cases, and because the Applicants knowingly withheld this information from the Commission before it adopted their TY 2012 GRC revenue requirements in D.13-05-010. This is an unjust result under the circumstances, and is due to the Applicants' withholding of material information that affected the adopted revenue requirement for TY 2012.

6.13.2.2.5.2. Rate Base Adjustments

We are persuaded by TURN's logic, as shown in Exhibits 400, 401, and 416, that over the long term, ratepayers for both SDG&E and SoCalGas will end up paying higher rates because the repair deductions were not recognized in the 2012 GRC. The Applicants' change in accounting method has reduced their income tax expense due to the higher amounts for repair expenses. However, this change also affects the future by lowering the amount of future depreciation deductions. We do not adopt TURN's recommendations to normalize the 2011-2014 portion of the repair allowance deduction.

Rather, similar to SCE's TY 2015 GRC (see D.15-11-021), we adopt a permanent reduction to the rate base of SoCalGas and SDG&E to offset the future tax expense related to the change in accounting method for the repairs deduction. This permanent rate base reduction is calculated such that the net present value of the Applicants' revenue requirement reductions equate to the net present value of future excess costs to ratepayers resulting from the election of the repairs deduction not being incorporated into their 2012 forecasts. We adopt these rate base reductions so that ratepayers would not have to bear the future higher costs resulting from the Applicants' election of the repair deductions and the Applicants' subsequent decision to flow through the tax savings from the election to shareholders rather than incorporating these savings in its 2012 GRC forecasts. Calculations for these rate base reductions are based on looking prospectively to the additional future costs that ratepayers have to pay.

This adjustment does not attempt to retrieve the $262 million in income tax savings that were flowed-through to the Applicants' shareholders. Based on the circumstances that the change in accounting method was never brought to the

Commission's attention before the TY 2012 GRC decision was issued for the Applicants, and the flow-through of benefits to shareholders from 2011-2015, we determine that a prospective adjustment to permanently reduce the rate base of SDG&E and SoCalGas is just and reasonable under the circumstances, and does not result in retroactive ratemaking. If an adjustment is not made to the rate base of the Applicants, unreasonable future rates will result from the Applicants' election to change their accounting method.

This permanent rate base adjustment is warranted because the results of the TY 2012 GRC period did not align with what occurred when the Applicants changed their method of accounting during the period of time covered by TY 2012. The Applicants were able to claim significantly more deductions for repairs beginning in 2011, than what the Applicants had forecast in their TY 2012 GRC applications. This is similar to what occurred in Pacific Telephone and Telegraph Company vs. PUC (1965) 62 Cal.2d 634, 645, in which the California Supreme Court stated the following:

> The test period is chosen with the objective that it present as nearly as possible the operating conditions of the utility which are known or expected to obtain during the future months or years for which the commission proposes to fix rates. The test-period results are 'adjusted' to allow for the effect of various known or reasonably anticipated changes in gross revenues, expenses or other conditions, which did not obtain throughout the test period but which are reasonably expected to prevail during the future period for which rates are to be fixed, so that the test-period results of operations as determined by the commission will be as nearly representative of future conditions as possible.

It is undisputed that the TY 2012 GRC applications of the Applicants did not incorporate the change in accounting method that the Applicants implemented in 2012 and 2013, and that D.13-05-010 adopted a revenue requirement based on an income tax expense forecast using the PRA methodology. For TY 2016, an adjustment for the period from 2016 through 2042 is warranted to recognize the long term impact of the changes to the Applicants' accounting methods which were never disclosed to the Commission during the pendency of their TY 2012 GRC applications, and which affect future rates. As TURN recommends, an adjustment is needed to recognize the effect of the changes in the amount of income tax expenses that the Applicants were able to claim as a result of the change in accounting method authorized by the Revenue Procedures. We adopted a similar adjustment in the recent GRC of SCE in D.15-11-021.[74]

If this adjustment is not made, the Commission would not be fulfilling its duty under Pub. Util. Code § 451 to ensure that all charges demanded or received by any public utility are just and reasonable. Merely because the timing of the change in accounting method fell between GRC reviews does not mean the utility should receive the benefits of such timing. Due to the long term impacts of the Applicants' change in accounting method, increased and unreasonable charges would result in the future, which is unlawful under this code section. The California Supreme Court has recognized that the Commission "has the power to prevent a utility from passing on to the ratepayers unreasonable costs." (City and County of San Francisco vs. PUC (1971) 6 Cal.3d 119, 126.)

The adjustment that we adopt today is consistent with Pub. Util. Code § 728 because hearings were held in this proceeding, and testimony was

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[74] The California Supreme Court has recognized that the Commission may make adjustments for taxes that have not actually been paid, and to protect against unreasonably inflated tax expense. See SoCalGas vs. PUC (1979) 23 Cal.3d 470, 477; City of Los Angeles vs. PUC (1975) 15 Cal.3d 680, 685; City and County of San Francisco vs. PUC (1971) 6 Cal.3d 119, 126.

presented by the parties regarding the deduction for repairs. Since the adoption of this adjustment mechanism applies prospectively, it does not violate Pub. Util. Code § 728.

As shown in Appendix B of this decision, we make permanent reductions to the rate base of SDG&E and SoCalGas in the amounts of $74.947 million, and $59.815 million, respectively.[75] These rate base reductions are based on the net present value of the future excess costs to ratepayers resulting from the Applicants' tax treatment for the repairs deductions from 2011-2015, compared to the cost if no change in the repairs deduction was made until 2016. As shown in Exhibit 416, the net present value of the future excess costs to SDG&E's ratepayers is $103.443 million, and to SoCalGas' ratepayers of $81.102 million. It would be unfair for ratepayers to bear these additional costs given what was forecasted by the Applicants in their TY 2012 GRC applications.

The rate base reductions have the effect of reducing SDG&E's revenue requirement for TY 2016 by $9.404 million ($1.624 million for gas, and $7.780 million for electric), and by $7.447 million for SoCalGas, as calculated by the RO model. The difference between the rate base reduction as calculated by the RO model, and what is shown in the rate base calculations in Appendix B, is described in Appendix B at the bottom of page 2 of 10.

The adjustments to rate base that we adopt in today's decision will ensure that ratepayers are not burdened with higher rates and costs going forward as a result of the Applicants' change in accounting method, and their decision to

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[75] As described in the sections discussing the rate base for SDG&E and SoCalGas, this adjustment for the repairs deduction reduces the amount of their respective rate base.

flow-through the tax savings to its shareholders rather than incorporating them into the 2012 GRC forecasted amounts.

In addition, and for the reasons stated above, we adopt TURN's proposal to flow-through the balance to ratepayers in the repairs deduction memorandum accounts that were in place for most of 2015. These memorandum accounts recorded the revenue impacts resulting from the election of the repairs deduction as compared to the PRA method. The Applicants shall file a Tier 1 AL within 30 days of the issuance of this decision to flow-through the balance in the account to ratepayers and to include workpapers showing how the balance was calculated.

Similar to what we ordered in SCE's TY 2015 GRC proceeding, SDG&E and SoCalGas shall each establish a two-way tax memorandum account to record any revenue differences resulting from the differences in the income tax expense forecasted in the GRC proceedings of SDG&E and SoCalGas, and the tax expenses incurred by them during the GRC period. The account shall remain open and the balance in the account shall be reviewed in every subsequent GRC proceeding until a Commission decision closes the account.

Along the same line, we expect, and will require, the Applicants to notify the Commission of any tax-related changes, any tax-related accounting changes, or any tax-related procedural changes that materially affect, or may materially affect, revenues, and to establish a memorandum account to track any revenue differences if applicable. Our reference to "materially affect" means a potential increase or decrease of $3 million or more. The failure to disclose such changes in a timely fashion undermines the integrity of the regulatory process, and may amount to a violation of Rule 1.

The establishment of a memorandum account is consistent with Resolution L-411A at 13 in which the Commission stated: "we believe that an even handed approach to regulation requires us to consider, when there has been a large and unexpected decrease in expenses between rate cases, whether it is appropriate to establish a memorandum account to allow for a future decrease in rates."

If the 2012-2015 repairs deduction estimated in this decision are different from the repairs deductions that the Applicants ultimately claimed in their tax returns, we also expect SDG&E and SoCalGas to bring this information to the Commission's attention. In this regard, SDG&E and SoCalGas should follow SCE's example when it filed AL 3368-E to reduce its revenue requirement because the 2012-2014 repairs deduction that was estimated in its 2015 GRC proceeding was lower than SCE claimed on its tax returns.

6.13.2.2.5.3. Retroactive Ratemaking Arguments

The adjustment that we adopt in today's decision, will not result in retroactive ratemaking. The Applicants' change in accounting method took place in between the GRC cycles for TY 2012 and TY 2016. In fact, the evidence is clear that SDG&E elected and implemented the change in the method of accounting beginning in 2012 (which first affected its 2011 income tax return), and that SoCalGas elected and implemented the change beginning in 2013 (which first affected its 2012 income tax return). The Applicants' witness testified that the change in accounting method was not included as part of their TY 2012 GRC filings (23 R.T. 2764-2765), which is substantiated by the Applicants' responses to TURN's data requests as set forth in TURN's Exhibits 400 and 401.

The Applicants make the argument that they have always been able to use the deduction for repairs, and that the income tax deduction was part of their TY 2012 GRC filings. The Applicants' suggest that because the deduction for repairs was considered as part of their income tax presentation in the TY 2012 GRC, that the Commission fully adjudicated the income tax deduction issue, and cannot retroactively change its TY 2012 decision. However, this argument overlooks the fact that the Commission was never made aware before a decision was issued on the Applicants' TY 2012 GRC applications, that a change in the method of accounting for the deduction of repairs was being contemplated by the Applicants, or that the Applicants elected to change their method of accounting for the deduction of repairs.

D.13-05-010, which addressed the Applicants' TY 2012 GRC applications, was not adopted by the Commission until May 9, 2013. As described in the responses to data requests as set forth in Exhibit 401, Revenue Procedure 2011-43, which SDG&E relied on to change its accounting method, was issued on August 19, 2011. In its 2011 10-K filing, which SDG&E filed with the Securities and Exchange Commission (SEC) around February 2012, included an income tax notation that included a tax adjustment using the PRA methodology, which is the methodology the Applicants used prior to 2012. SDG&E then engaged an accounting firm to perform studies in February and April of 2012 to determine whether the change in methodology as set forth in Revenue Procedure 2011-43 would increase the repairs deduction over the PRA methodology. On September 5, 2012, SDG&E notified the IRS of its intent to change its accounting method, and then implemented the change to its 2011 income tax return around the September 2012 timeframe.

With respect to SoCalGas, it relied on Revenue Procedure 2012-19, which was issued on March 7, 2012. Revenue Procedure 2012-19 replaced an earlier version of the tax guidance that was set forth in Revenue Procedure 2011-14, which was issued on January 10, 2011. The IRS also issued its temporary tangible property regulations on December 23, 2011, which provided further guidance on the expensing and capitalization of expenditures to acquire, repair, and dispose of tangible property. In March 2012, after considering Revenue Procedure 2011-19 and the temporary tangible property regulations, SoCalGas engaged an accounting firm to determine whether an increased repair deduction could be claimed over the amount that could be claimed using the PRA methodology. A full workup of the repairs deduction was started on July 18, 2012. On August 20, 2013, SoCalGas informed the IRS of its intent to implement the change in accounting method to the repairs deduction. SoCalGas then applied the change in the accounting method to its 2012 income tax return around the August 2013 timeframe.

The facts described above demonstrate that the TY 2012 GRC applications, which were filed with the Commission on December 15, 2010, did not advise the Commission or the parties of the possible change in accounting method. This is understandable since the IRS had not yet issued Revenue Procedure 2011-43, Revenue Procedure 2011-14, or the temporary regulations on tangible personal property. However, the question is raised why the Applicants did not inform the Commission and the parties of the developments regarding the change in the accounting method before a decision was issued on the Applicants TY 2012 GRC applications. There were certainly opportunities for the Applicants to do so since evidentiary hearings in the Applicants' TY 2012 GRC applications did not begin until November 30, 2011, and did not conclude until January 26, 2012. Opening briefs in the TY 2012 GRC proceedings were not filed until April 3, 2012, and a decision regarding the issues in the TY 2012 applications was not adopted until May 9, 2013. All of these events occurred after Revenue Procedure 2011-43 had been issued.

SDG&E began the process of deciding whether it would be beneficial to utilize the change in accounting method beginning in February 2012, two months before opening briefs were filed. SDG&E then implemented the change in accounting method around September 2012, at least five months before a proposed decision was issued on March 29, 2013 addressing the Applicants' TY 2012 GRC applications.[76] Although the Applicants were aware around February to April of 2012 that the change in accounting method could increase the repairs deduction, and took steps to implement the change in September 2012, the Applicants never filed a motion to set aside submission and to reopen the record, as permitted by Rule 13.14 of the Commission's Rules of Practice and Procedure. Nor did the Applicants request a Z-factor adjustment, even though the Preliminary Statement of both SDG&E and SoCalGas specifically state that tax law changes by the federal government fall within a Z-factor adjustment. Instead, both SDG&E and SoCalGas proceeded forward, without informing the Commission of the significant differences in what they had forecast in their TY 2012 GRC applications, and what they were doing.

The facts show that the Commission and the other parties were never informed by the Applicants before the adoption of D.13-05-010 of the differences between what was originally forecasted in the TY 2012 GRC filings and the extra savings in income tax that SDG&E and SoCalGas would receive as a result of the higher than forecasted deductions for repairs. One could make the argument that the Applicants' failure to bring these material differences to the attention of the Commission should be considered a violation of Rule 1 of the Commission's Rules of Practice and Procedures. Rule 1 provides:

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[76] We also take official notice of Sempra's Form 10-Q Quarterly Report, filed with the SEC on November 6, 2012, in which Sempra discussed the decrease in income tax expense due primarily to a change in the income tax treatment of certain repairs.

> Any person who signs a pleading or brief, enters an appearance, offers testimony at a hearing, or transacts business with the Commission, by such act represents that he or she is authorized to do so and agrees to comply with the laws of this State; to maintain the respect due to the Commission, members of the Commission and its Administrative Law Judges; and never to mislead the Commission or its staff **by an artifice or false statement of fact or law.** (Emphasis added.)

The Applicants' failure to inform the Commission of material changes to its tax repair expense, despite opportunities to do so, supports the Commission adopting an adjustment to the Applicants' revenue requirements.

The Applicants suggest that because the Commission reviewed the deductions for repairs as presented in their TY 2012 GRC applications, the Commission is now without authority to adopt an adjustment to the repairs deduction that occurred in the 2011 to 2015 timeframe. The Applicants contend that to do so, the Commission would be in violation of the prospective relief described in Pub. Util. Code § 728. However, the Applicants' theory hinges on the assumption that the Commission reviewed the Applicants' forecasted amounts, and issued a decision based on those amounts. As described above, the Commission never had the opportunity to review the change in accounting method that began around September 2012, and which continued in between the TY 2012 and TY 2016 GRC proceeding cycles. Instead, D.13-05-010 addressed the deduction of repairs using the PRA methodology, which is the methodology that preceded Revenue Procedure 2011-43 and Revenue Procedure 2012-19. SDG&E then used the change in accounting method in 2012, and SoCalGas took action to begin using the change in accounting method in 2013, before the Commission issued D.13-05-010.

Under the Applicants' theory, because the change in their accounting methods took place in between rate case proceedings, their transactions should escape scrutiny because D.13-05-010 already reviewed and approved the Applicants' 2010 and 2011 testimony regarding income tax expense. The Applicants contend that since the change in accounting method took place in between rate case proceedings, any underestimate or overestimate in the TY 2012 decision cannot be adjusted. Also, under the Applicants' theory, because the change in accounting method took place in between GRC proceedings, and because the Commission has historically treated deductions for repairs on a flow-through basis, the Applicants should be able to continue the flow-through treatment of the significantly higher deductions for repairs to benefit their shareholders who pocketed the savings that resulted from the payment of lower income taxes during the 2011 to 2015 period.

Based on the circumstances, we are not persuaded that the adjustment that we make in today's decision, amounts to retroactive ratemaking. The income tax expense presented in the Applicants' TY 2012 GRC applications, and the failure of the Applicants to disclose these changes to the Commission's attention during the pendency of a decision on the Applicants' TY 2012 applications, did not provide the Commission with an accurate forecast of the deductions for repairs that would be taken over the course of the 2012 to 2015 GRC cycle. The decision (D.13-05-010) approving the reasonableness of the TY 2012 GRC forecast of the income tax expenses was based on the continued use of the PRA methodology. Thus, D.13-05-010 never reviewed or considered the true nature of the changes in the accounting method that the Applicants pursued during the timeframe when the TY 2012 GRC applications were still pending before the Commission. The Applicants should not be able to shield their actions of changing their accounting method by asserting that the rate base adjustment results in retroactive ratemaking, when at the time the TY 2012 GRC decision was issued, the Commission knew nothing about what the Applicants were planning to do.

Under the Applicants' theory, the Commission would never have a meaningful opportunity for such a review, and would have no authority to adjust rates going forward or to take other action in order to achieve a more reasonable outcome. To allow this material change to escape the Commission's review merely because of the Applicants' timing of the tax change, and the Applicants' failure to bring this material change to the attention of the Commission, would be unjust and unreasonable under the circumstances. Contrary to the Applicants' theory, the Commission can exercise regulatory oversight over outcomes the utility chose without approval by the Commission.

In addition, the change in accounting method was not due to productivity savings on the part of the Applicants. Although the Applicants contend that any productivity savings that occur during a GRC rate cycle benefit shareholders, the income tax savings are directly attributable to the change in accounting method authorized by the IRS and not as a result of productivity increases.

For the above reasons, we conclude that retroactive ratemaking and Pub. Util. Code § 728 do not apply to the facts of these events, and do not prevent us from making the adjustments discussed in this section.

6.13.2.2.5.4. Equitable Concerns

Furthermore, to allow the Applicants to pocket the income tax savings resulting from the changes to their accounting methods would be inequitable. We agree with TURN that the Applicants were able to time their elections to change their accounting methods and the resulting tax benefit flowed to the benefit of their shareholders.[77]

Although the timing of the change appears justified by the guidance provided by the Revenue Procedures, the fact remains that the Applicants failed to disclose these material changes to their income tax expense to the Commission and the other parties in a timely manner. During the Applicants' implementation and consideration of the changes to their accounting of the repairs deduction in 2012 and 2013, the Applicants could have but chose not to disclose this to the Commission before D.13-05-010 was issued. Indeed, this issue was not brought to the Commission's attention until the Applicants filed their TY 2016 GRC applications on November 14, 2014.

Due to the Applicants' decision to withhold the information that it took the repairs deduction during the time the TY 2012 GRC proceeding were still open, and the subsequent tax savings flowed-through to the Applicants' shareholders, the Commission should take action to rectify this result. Had the change in accounting method been considered in the TY 2012 GRC applications, the tax savings would have flowed-through to ratepayers. The Court of Appeals stated in Pacific Bell Wireless, LLC vs. PUC (2006) 140 Cal.App.4th 718, 743, that Pub. Util. Code § 728 "does not prohibit retroactive punishment for imposition of unreasonable rates." The Court of Appeals also stated that a "company's action can be unjust or unreasonable without a specific rule of statute prohibiting it," and that no utility "should expect to be insulated from the obligation to treat its customers fairly." (*Id.* at 744.)

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[77] The change in the accounting method, which resulted in less income tax being paid, is also a factor in deciding whether incentive compensation should be awarded. (See 21 RT 2425.)

6.13.2.2.5.5. No Normalization Violation

The normalization rules govern the ratemaking treatment of the temporal differences arising from accelerated depreciation for book and tax purposes. These normalization rules are set forth primarily in IRC § 168(i)(9), Treasury Regulation § 1.167(l)-1, and pertinent IRS rulings.

The Applicants assert that the rate base reduction constitutes a "loss of accelerated depreciation treatment" and would likely be deemed by the IRS to violate the normalization rules. (Applicants' Opening Brief at 40-41.) The Applicants contend that the normalization rules may be violated "when the reserve for deferred taxes that reduces rate base is computed using projections or forecasts that are inconsistent with the projections and forecasts used to compute income tax expense and depreciation." (*Ibid*.) The deferred tax reserve that the Applicants refer to is the ADIT. As framed by the Applicants, ADIT for ratemaking purposes cannot be calculated differently than ADIT for tax purposes, and ADIT for ratemaking purposes cannot be greater than ADIT for tax purposes. This argument is the same type of argument that SCE raised in connection with the rate base adjustment addressed in D.15-11-021. Our response to SCE's argument in D.15-11-021 at 448 is instructive here:

> SCE's characterization of "additional deferred taxes" is inconsistent with the normalization rules. [Treasury Regulation] § 1.167(l)-1(h)(1)(iii) provides that deferred taxes are calculated with respect to "actual" tax liability, but SCE defines deferred taxes with respect to the depreciation "that would have resulted" if it did not make the Rev. Proc. 2011-43 election. Rev. Proc. 2011-43 permits an electric utility to recognize current-year business expense deductions for amounts that would have been capitalized but for the safe harbor election. In other words, SCE's "additional deferred taxes" depend on depreciation "that would have resulted" if SCE had more depreciable basis than it in fact had. That addition to basis never

occurred, and therefore the rate base adjustment cannot be a tax deferral.

In other words, the utility can either preserve the repair costs as depreciable basis, which will be normalized when recognized, or it can realize those costs as immediate deductions, not both.

The rate base reductions we make are not ADIT. ADIT is an account to record deferred income tax expense. The rate base reductions that we adopt today, are not in the form of any accounts.

Moreover, the change in method of accounting for repair costs had the effect of recognizing repair costs as an immediate deduction. Those costs, however, were never capitalized.[78] Accelerated depreciation is calculated on depreciable basis.[79] Since the repair costs never were assigned a depreciable basis, they cannot contribute to accelerated depreciation and therefore cannot be normalized.

The disconnect between the rate base reduction and ADIT is most easily demonstrated with a simple hypothetical. ADIT for accelerated depreciation is calculated as the difference between using accelerated depreciation for taxes and a different method of depreciation for book.[80] If the Applicants had used straight-line depreciation for both actual and regulatory tax expense, then ADIT for accelerated depreciation could never result. Treasury Regulation § 1.167(l)-1(h)(1)(iii) provides that the amount of deferred income tax is the difference in

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[78] Treasury Regulation § 1.162-4(a) states "A taxpayer may deduct amounts paid for repairs and maintenance to tangible property if the amounts paid are not otherwise required to be capitalized."

[79] IRC § 167©(1).

[80] Treasury Regulation § 1.167(l)-1(h)(1)(iii).

tax liability from using accelerated depreciation versus straight-line. Here that difference would be zero.

But given that Applicants chose to elect the repairs deduction and flow the tax savings to shareholders rather than incorporating them into their TY 2012 GRC forecasts, ratepayers did not receive any tax savings from the election but will incur future higher taxes due to the decrease in future depreciation deductions. The Commission has the regulatory authority to order a rate base reduction to compensate for the undisclosed decrease in depreciable basis. Since there is no accelerated depreciation, our rate base reductions are not ADIT. Our rate base reductions compensates ratepayers for the future increase in tax expense caused by the loss of depreciation deductions that were instead recognized as repair deductions.

The adjustment we adopt today, merely correct for an unforecasted increase in tax expense that resulted from the undisclosed change in the Applicants' method of accounting. Accordingly, we believe our approach is consistent with, and does not violate the normalization rules.

To ensure that the rate base reductions we adopt today do not violate IRS normalization rules, SDG&E and SoCalGas shall submit a private letter ruling to the IRS to request a review that these rate base reductions do not violate the normalization rules. Before SDG&E and SoCalGas submit the private letter rulings to the IRS, the Applicants must each file a Tier 1 AL with the Energy Division with a copy of their proposed letters to the IRS.

6.13.2.3. Bonus Depreciation

Bonus depreciation refers to a situation where a taxpayer is allowed to claim an additional amount of deductible depreciation above what is normally available. Essentially, bonus depreciation is a form of accelerated depreciation.

According to SoCalGas and SDG&E, the ratemaking effect of bonus depreciation is to increase federal tax return depreciation in the year it is taken above the regular tax depreciation provided by the federal Modified Accelerated Cost Recovery System (MACRS) depreciation system.

SDG&E and SoCalGas state that the "Differences between book and tax depreciation resulting from the different lives and methods used to compute book and tax depreciation are normalized." (Exhibit 244 at 10; Exhibit 247 at 13.) The difference that occurs between the bonus depreciation method, and the tax depreciation using MACRS, is accounted for in the ADIT. According to the Applicants, the extra bonus tax depreciation created by these extension results in the creation of "additional deferred taxes equal to the extra bonus depreciation multiplied by the 35% federal income tax rate." (Exhibit 244 at 14; Exhibit 247 at 17.) The ADIT is then used as an offset to reduce the rate base.

Bonus depreciation is an issue because it has tax implications for the Applicants' TY 2016 revenue requirement and beyond. The bonus depreciation issue originates from three pieces of federal tax legislation that the United States Congress passed, two of which were referred to in the Applicants' TY 2016 testimony.

The first piece of legislation is the American Taxpayer Relief Act of 2012 (ATRA). The ATRA was enacted into law on January 2, 2013 as Public Law 240 of the 112th Congress. The ATRA included a one year extension of the 50% bonus depreciation for eligible property placed into service before January 1, 2014, and for costs incurred before January 1, 2014 attributable to eligible long production period property placed into service before January 1, 2015.[81]

The second piece of legislation is the Tax Increase Prevention Act of 2014 (TIPA), which was enacted into law on December 19, 2014 as Public Law 295 of the 113th Congress. The TIPA included a provision to extend the 50% bonus depreciation for one year retroactive to January 1, 2014. This 50% bonus depreciation applies to eligible property placed into service before January 1, 2015, and for costs incurred before January 1, 2015 attributable to eligible long production period property placed into service before January 1, 2016.

The third piece of legislation is known as Protecting Americans From Tax Hikes Act of 2015 (PATH), which was enacted into law of December 18, 2015 as Public Law 114-113 of the 114th Congress. The PATH includes a provision which extends bonus depreciation under the following phase-down schedule through 2019: at 50% for 2015-2017; at 40% in 2018; and at 30% in 2019.

In the Applicants' TY 2016 GRC applications, only the ATRA and TIPA were mentioned in the testimony accompanying the applications.[82] The testimony for the Applicants' TY 2016 GRC applications did not mention the PATH act, because that act was not enacted until December 18, 2015, a little over one year from when the Applicants' TY 2016 GRC applications were first filed.

In Exhibit 394 at 2, ORA recommended the following:

> Appropriate adjustments to the forecast of SDG&E's and [SoCalGas'] tax expenses should be updated once the Tax-Extenders Bill or other tax related bills are approved, resulting in changes to

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81 Prior to ATRA, which extended bonus depreciation for tax year 2013, bonus depreciation had been authorized in other pieces of federal legislation.x (See D.13-05-010 at 943-944.)

82 See Exhibit 244 at 13-14, and Exhibit 247 at 16-17.

> the tax code related to depreciation, bonus depreciation and or tax rates in this GRC that occur prior to a final Commission decision.

Then in Exhibit 398 at 18, ORA stated:

> SDG&E and SoCalGas have modeled the impacts of bonus depreciation only for 2014 in this rate case. If provisions for bonus depreciation are extended into any years beyond 2014, through the end of this rate case cycle, the Sempra Utilities should be required to make the appropriate revenue requirement adjustments to reflect the impacts from bonus depreciation so that the benefits are flowed through to ratepayers. As indicated previously, the full benefits should be included in SDG&E's and SoCalGas' post-test year advice letters.

These recommendations of ORA are consistent with its earlier statement in Exhibit 394 at 1 that:

> The test year tax expense estimate should reflect, to the extent possible, the actual tax expense incurred by the regulated enterprise. In D.84-05-036, the Commission stated, "(f)or the present, we will continue our current policy regarding flow-through treatment of timing differences consistent with applicable tax law." [15 CPUC 2d 42, 54.] ORA recommends that the Commission continue to adopt policies which result in the test year tax estimates reflecting, to the extent possible, the actual "real world" tax expense incurred by the regulated enterprise.

In response to ORA, the Applicants stated the following in Exhibits 246 and 249 at 3:

> [SoCalGas/SDG&E] will follow the procedures and deadlines set forth in the Rate Case Plan and Scoping Memo for updating its forecasts to reflect tax law changes, including tax-extender legislation, extension of bonus depreciation, or other tax-related law changes that occur prior to the closing of the record in this GRC. ORA's proposal would go beyond the procedures set forth in the Rate Case Plan and Scoping Memo and would require [SoCalGas/SDG&E] to update its forecasts after the record in this GRC has closed. Accordingly, ORA's proposal should not be adopted.

In the Attachment 1 Settlement Agreement to the SDG&E Settlement Motion, and to the SoCalGas Settlement Motion, the settling parties addressed bonus depreciation by stating that the Applicants have "modeled the impacts of bonus depreciation only for 2014," and that "The settlement does not address the merits of the parties' arguments or prejudice any party's ability to raise this issue again in an upcoming GRC." (SDG&E Settlement Comparison Exhibit at 303; SoCalGas Settlement Comparison Exhibit at 241.) Based on those statements, and a review of the revenue requirements agreed to in the Attachment 1 Settlement Agreement of both SDG&E and SoCalGas, no adjustments were made by the settling parties to reflect the extension of bonus depreciation for 2015 through the TY 2016 GRC rate cycle ending in 2018.

Our reasoning as to why an adjustment should be made for bonus depreciation is similar to our adjustment for the repairs deduction. First, the TY 2016 GRC applications of the Applicants reflect bonus depreciation as a result of ATRA (tax year 2013) and TIPA (tax year 2014). With the enactment of PATH, bonus depreciation should be reflected for tax years 2015 through 2018. If the bonus depreciation from PATH is not reflected during the TY 2016 GRC cycle for SDG&E and SoCalGas, their revenue requirements are likely to be higher and their ratepayers will pay higher rates as a result.

Second, just as the election to change the accounting method for the repairs deduction was known before a decision was rendered on the Applicants' TY 2016 GRC applications, the effects of the PATH are also known, and the Applicants can take advantage of the bonus depreciation for tax years 2015 through 2018. The additional depreciation that can be claimed under the PATH extension of bonus depreciation is likely to have a material effect on the depreciation that can be claimed. As noted by SDG&E and SoCalGas, "The ratemaking effect of the ATRA and the TIPA is to increase federal tax return depreciation in 2013 and 2014 (and in 2015 for qualified long production period property) above the regular tax depreciation provided by the federal MACRS depreciation system." (Exhibit 244 at 14; Exhibit 247 at 17.) Thus, since the PATH extended bonus depreciation for 2015 through this GRC cycle, an adjustment to account for the bonus depreciation should be made in today's decision for SDG&E and SoCalGas.

Third, the settling parties agree in the Attachment 1 Settlement Agreement for both SDG&E and SoCalGas that the "settlement does not address the merits of the parties' arguments" regarding bonus depreciation. However, that provision of the SDG&E settlement and the SoCalGas settlement is unreasonable and not in the public interest because the Applicants' ability to use the extension of the bonus depreciation for the tax years of 2015 through 2018 will have a material effect on the Applicants' depreciation, ADIT, and return on rate base. If the effects of the PATH are not reflected in the TY 2016 GRC cycle, the ADIT for TY 2016 will be lower, which will increase the amount of rate base, which in turn will result in an increase of the Applicants' return on rate base.

In addition, we take official notice of Sempra's 2015 Annual Report, and its Form 10-K filing with the SEC on February 26, 2016. Both of those documents reflect the actions the Applicants took with respect to bonus depreciation in tax year 2015. To ignore the effects of the PATH, when the Applicants have applied bonus depreciation for 2015, and presumably will do so for tax year 2016, would be unreasonable and not in the public interest.

For all of the above reasons, and because the revenue requirement amounts agreed to in the SDG&E and SoCalGas Settlement Motions do not reflect the effects of the extension of bonus depreciation for 2015 and 2016, we conclude that the settling parties' agreement not to address the merits of the parties arguments on bonus depreciation is unreasonable, is not in the public interest, and that portion of the Attachment 1 Settlement Agreements should be rejected.[83]

Due to the rejection of the settling parties' agreement with respect to bonus depreciation, we adopt an adjustment to the TY 2016 revenue requirements of SDG&E and SoCalGas that reflects the inclusion of bonus depreciation for tax years 2015 and 2016. In Section 5 of Appendix B of today's decision, we show the file names of the adjustments to the RO model for bonus depreciation. By including bonus depreciation for 2015 and 2016, this results in a reduction of $9.390 million to the revenue requirement of SDG&E, and a reduction of $12.784 million to the revenue requirement of SoCalGas.

We note that such an adjustment to the TY 2016 revenue requirements of SDG&E and SoCalGas is consistent with the Rate Case Plan in which the update testimony and exhibit is to include "Known changes due to governmental action such as changes in tax rates…," which could result in "decreases as well as increases." (D.07-07-004, Appendix A at A-36.) Although the PATH act was enacted after the August 17, 2015 date set for submitting the update testimony and exhibit had passed, this is a situation in which "a change in the tax laws" appears "permanent and substantial," and the Commission should exercise its

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[83] As noted earlier, the portion of the settlement that states that the merits of the parties' arguments on bonus depreciation is not addressed, is found in the SDG&E Settlement Comparison Exhibit at 301, and in the SoCalGas Settlement Comparison Exhibit at 256.

discretion to take into account the "changes in tax laws." (D.84-06-036 [15 CPUC 2d 42, 53].)[84]

Failing to account for this change in the tax law, which was enacted into law on December 18, 2015, is not in the public interest because of the effect on the revenue requirements, and the rates that ratepayers will have to pay. Since this is a known change in the tax law, and because today's decision regarding TY 2016 is the first opportunity to reflect the extension of bonus depreciation as a result of the PATH, our adjustments to the TY 2016 GRC revenue requirements of SDG&E and SoCalGas are justified.

6.13.3. Taxes Other Than on Income

Line 25 of the summary of earnings tables in the Attachment 1 settlement agreement shows the amounts for taxes other than income taxes. These taxes are composed of payroll taxes, and ad valorem taxes (more commonly referred to as property taxes). SDG&E requests a total amount of $94.746 million, which is composed approximately of $17.701 million for payroll taxes, and ad valorem taxes of $76.999 million. The payroll taxes are composed of the following three elements: (1) Federal Insurance Contributions Act (FICA), more commonly referred to as social security and medicare; (2) Federal Unemployment Tax Act; and (3) the California State Unemployment Insurance (CSUI). The ad valorem

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[84] Similarly, in Resolution L-411A, the Commission ordered a number of utilities to establish memorandum accounts to track the impacts of a change in tax law resulting from the enactment of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. This 2010 act allowed 100% bonus depreciation on certain business property put into service after September 8, 2010 and before January 1, 2012, and for 50% bonus depreciation for property placed into service thereafter and before January 1, 2013 and for property placed into service in 2013 where construction begins prior to January 1, 2013.

taxes are based on the assessed value of the property and the tax rate that is applied.

ORA recommends a total amount of $86.587 million for payroll taxes and ad valorem taxes. In Exhibit 394, ORA recommends that SDG&E's calculation of payroll taxes use updated wage bases under FICA, and the 2015 tax rate under the CSUI. For ad valorem taxes, ORA agrees with SDG&E's forecast for property taxes and SDG&E's proposed tax rate. The differences between the ad valorem forecasts of SDG&E and ORA are due to the differences in their respective TY 2016 estimate of plant additions.

In the combined summary of earnings table in the Attachment 1 settlement agreement, the settling parties have agreed to an amount of $91.325 million. In the SDG&E Settlement Comparison Exhibit under the heading of "Other Issues," which appears at page 14, the settling parties agree to ORA's forecasted payroll tax rate of 6.81%. This payroll tax rate is one of the elements that make up the $91.325 million amount.

Based on a comparison of how SDG&E and ORA developed their forecasts of payroll taxes and property taxes, and the methodology agreed to in the SDG&E Settlement Agreement, it is reasonable to adopt the methodology that the settling parties agreed to for taxes other than income, as adjusted by the bonus depreciation adjustment, and which generated the amount of $90.874 million.

6.14. Rate Base and Return on Rate Base

6.14.1. Introduction

The last three components of calculating the revenue requirement are rate base, the rate of return, and the return on rate base. These three components are shown at lines 27 to 29 of SDG&E's summary of earnings tables. The amount of the rate base is multiplied by the authorized rate of return to produce the return on rate base. This return on rate base is added to the other components, which when added together, totals to the requested revenue requirement.

6.14.2. Rate Base

SDG&E defines rate base "as the net investment of property, plant, equipment and other assets that SDG&E has acquired or constructed to provide utility services to its customers." (Exhibit 293 at 2.) As defined by ORA, the rate base "is the depreciated asset value of the utility's net investments used to provide service to its customers." (Exhibit 396 at 1.) As described in Exhibit 293, the four major components of rate base are fixed capital, working capital, other deductions, and deductions for reserves.

In SDG&E's update testimony, SDG&E requested a rate base amount of $5,321,539,000 in its update testimony. In SDG&E's rate base testimony in Exhibit 293, SDG&E originally requested a rate base amount of $5,307,766,000.

SDG&E's derivation of the rate base is explained in Exhibit 293, which is based in large part on the testimony of other witnesses regarding the capital expenditure levels. This derivation includes a description of the four major components of rate base, and the various elements which make up these components. As described in Exhibits 234 and 293, these elements include the following: allowance for funds used during construction; contributions in aid of construction; and working cash, which is developed from the revenue lag studies. The working cash, along with the costs of materials and supplies, make up the working capital component of the rate base.

In Exhibit 396, ORA recommended a rate base amount of $4.902 billion for SDG&E.[85] However, in the SDG&E Settlement Comparison Exhibit at 333, and in ORA's Exhibit 367 at 9, ORA's rate base amount is shown as $4,914,746,000. ORA's derivation of the rate base amount is based on the testimony of other ORA witnesses as noted in Exhibit 396 at 2.

In Exhibit 396, ORA also recommended a working cash amount for SDG&E of $92.659 million, which is lower than the working cash amount of $136.056 million that SDG&E had originally requested. ORA's recommendation for a lower working cash amount is because of the following reasons, as more fully explained in Exhibit 396: (1) SDG&E's cash balances should be excluded from the working cash calculations; (2) ORA's use of 39.92 as the revenue lag days for the working cash calculations, instead of SDG&E's use of 40.35 days; (3) ORA's use of 37.50 for the federal income tax lag days, instead of SDG&E's use of zero days; (4) ORA's use of 20.60 for the CCFT lag days, instead of SDG&E's use of a negative 407.12 days; and (5) ORA's recommendation that customer deposits should be treated as a source of debt, which should result in a $2.480 million reduction to SDG&E's revenue requirement.

FEA supported ORA's recommendations on working cash.

In Exhibit 400, TURN raised its own issues about working cash including objecting to SDG&E's inclusion of preliminary survey and investigation costs as part of its working cash requirement.

At line 28 of SDG&E's combined summary of earnings table in the Attachment 1 settlement agreement of the SDG&E Settlement Motion, the agreed

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[85] Due to rounding, the amount of $4.903 billion also appears in Exhibit 366 at 26.

upon amount of $5,133,222,000 is shown for rate base. This rate base amount of approximately $5.133 billion is derived from the capital-related costs that the settling parties have agreed upon.

In addition to the $5.133 billion for rate base that the settling parties have agreed upon in the Attachment 1 Settlement Agreement, the settling parties also agreed to certain working cash related issues as shown in the SDG&E Settlement Comparison Exhibit at 13. The settling parties have agreed to the following working cash issues: (1) to ORA's forecast for cash balances of $0; (2) to SDG&E's forecast for revenue lag days of 40.35; (3) to ORA's forecast for federal income tax lag days of 37.50; (4) to ORA's forecast for state income tax lag days of 20.60; and (5) to ORA's "revenue requirement adjustment of $2.480 million ($2.057 million electric and $0.423 million gas), which in this instance only matches amounts as if customer deposits were treated as a source of debt," but "does not resolve the policy issue of whether customer deposits are to be henceforth treated as a source of debt."

In the Attachment 5 Settlement Agreement between SDG&E and TURN and UCAN, these three parties have agreed that SDG&E's rate recovery of any of the costs associated with the Manzanita wind project and transmission interconnection for that project will be limited to the amount received for the return on cash working capital for preliminary surveys and investigations in this 2016 GRC cycle. SDG&E also agrees that it will not seek rate recovery of any of the costs associated with the Manzanita project in any future rate case at the Commission or at the FERC.

Comparing the positions of SDG&E, ORA, FEA and TURN on the amount of rate base that should be included in the calculation of the return on rate base, the capital-related costs that the settling parties have agreed to, and the adjustment that we adopt for the repairs deduction, it is reasonable to adopt the amount of $4,976,815,000 as the rate base amount. In addition, the provision in the Attachment 5 Settlement Agreement about working cash for the Manzanita wind project is reasonable and should be adopted.

6.14.3. Rate of Return

Line 29 of SDG&E's summary of earnings tables shows the 7.79% rate of return that SDG&E uses to calculate the total revenue requirement. The 7.79% is the rate of return that reflects what the Commission approved in the 2013 TY cost of capital proceeding in D.12-12-034.[86]

6.14.4. Return on Rate Base

Using the adjusted rate base amount of $4,976,815,000 and the rate of return of 7.79%, that results in the TY 2016 return on rate base amount of $387.694 million as shown on line 27 of SDG&E's combined summary of earnings table in the Attachment 1 settlement agreement. The return on rate base is added to the O&M cost, depreciation, and taxes, which results in the total revenue requirement.

6.14.5. Rate Stabilization Agreement

In the Attachment 5 Settlement Agreement of the SDG&E Settlement Motion, TURN and UCAN agree with SDG&E that the rates for SDG&E's customers will be adjusted on January 1, 2016 to reflect the roll-off of the GRC memorandum account balances associated with SDG&E's 2012 GRC, irrespective of the timing of a final decision in SDG&E's TY 2016 GRC.

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[86] The next cost of capital proceeding is expected to occur in 2017.

SDG&E's rate stabilization proposal is described in Exhibit 203. SDG&E proposed in part that "In the event that SDG&E does not receive a decision in time to implement rates effective January 1, 2016, SDG&E proposes to not adjust rates for the roll-off [GRC Memorandum Account] balances associated with its 2012 GRC Phase 1 in order to avoid rate volatility for our customers and until such time the 2016 GRC is implemented."

In accordance with the agreement reached on rate stabilization in the Attachment 5 Settlement Agreement, SDG&E filed Advice Letter 2807-E on October 30, 2015 to adjust its GRC Memorandum Account. Advice Letter 2807-E was approved on November 23, 2015.

This provision of the Attachment 5 Settlement Agreement to the SDG&E Settlement Motion is reasonable, and should be adopted. SDG&E has taken action through Advice Letter 2807-E to effectuate this part of the Attachment 5 Settlement Agreement.

6.15. Miscellaneous Revenues

Miscellaneous revenues appear at lines 2 and 36 of SDG&E's combined summary of earnings table. According to SDG&E, "Miscellaneous revenues are comprised of fees and revenues collected by the utility from non-rate sources for the provision of specific products or services." (Exhibit 231 at 1.) As described in Exhibit 231, these miscellaneous revenues include service establishment charges, collection charges, other fees, and rents.[87] When the miscellaneous revenues are added to the base margin revenue requirement, that adds up to the total revenue

[87] The miscellaneous revenues include only those revenues allocated to the electric distribution and gas departments, and "excludes miscellaneous revenues associated with electric transmission properties and facilities, wheeling charges and other non-distribution sources recovered through FERC-jurisdictional ratemaking mechanisms." (Exhibit 231 at 2.)

requirement. These miscellaneous revenues reduce the amount of the revenue requirement that is charged to customers.

In its updated testimony, SDG&E proposed miscellaneous revenues of $19.235 million. Originally, SDG&E proposed miscellaneous revenues of $19.225 million in Exhibit 231.

In ORA's update testimony in Exhibit 366, and in ORA's testimony on miscellaneous revenues in Exhibit 371, ORA forecasted $20.344 million in miscellaneous revenues.[88] As described in Exhibit 371, ORA took issue with SDG&E's forecast of the service establishment charge revenues for the electric and gas operations. The use of ORA's methodology resulted in higher service establishment charge revenues.

In SDG&E's rebuttal testimony in Exhibit 233, SDG&E disagreed with ORA's methodology because ORA ignored the remote connection capability of SDG&E's smart meter, and did not fully account for how the service establishment fees will be reduced because of the remote service capabilities.

Although UCAN agreed with the cost savings associated with the remote connection capability of the smart meters, UCAN disagreed with SDG&E's changes to the fees paid by customers. UCAN recommended setting a single service establishment charge. In Exhibit 233, SDG&E's witness stated that UCAN's recommendation was not consistent with establishing cost based fees.

In SDG&E's combined summary of earnings table in the SDG&E Settlement Motion, the settling parties have agreed to the amount of $20.061 million for miscellaneous revenues. At page 14 of the SDG&E Settlement

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[88] In ORA's combined summary of earnings table in Exhibit 367, the amount of $19.986 million is shown for miscellaneous revenues.

Comparison Exhibit, the settling parties specifically "agree to ORA's service establishment forecast of $5.393 million ($3.560 million for Electric, $1.833 million for Gas)."[89]

In the Attachment 5 Settlement Agreement to the SDG&E Settlement Motion, the settling parties agree that SDG&E's service establishment charge will be set at $5.85 for all customers. None of the parties have objected to this part of the Attachment 5 Settlement Agreement.

We have reviewed the original positions of SDG&E, ORA, and UCAN. We have also compared their positions to the amounts agreed to in the Attachment 1 Settlement Agreement of the SDG&E Settlement Motion, and to the agreement in the Attachment 5 Settlement Agreement regarding the amount of the service establishment charge. Based on their original positions, and the amount agreed upon in the Attachment 1 settlement agreement, it is reasonable to adopt the amount of $20.061 million ($15.854 million for electric, and $4.207 million for gas) for SDG&E's miscellaneous revenues.[90] It is also reasonable to adopt the agreement in the Attachment 5 Settlement Agreement to set SDG&E's service establishment charge for all customers at $5.85. Setting this charge at $5.85 will avoid having separate fee structures for service establishment activities that involve a field visit and those that do not require a field visit.

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89 As shown in ORA's Exhibit 371 at 2, the agreed upon amounts for the service establishment charges are some of the revenue elements that add up to the total amount of miscellaneous revenues.

90 As shown on SDG&E's combined summary of earnings table, we note that the RO model generated a slightly smaller amount of $20.057 million.

6.16. Post Test Year Ratemaking

6.16.1. Introduction

The PTY period covers the years following TY 2016. In its application, SDG&E originally proposed a three year term for this GRC cycle, consisting of TY 2016 and the attrition years of 2017 and 2018.

As part of its application, SDG&E proposed a PTY ratemaking mechanism to cover the attrition years to adjust the authorized revenue requirements for the O&M expenses and the capital related expenditures. In addition, SDG&E proposed that the Z-factor mechanism be continued without any change. ORA does not oppose continuing the Z-factor mechanism, but recommends that the mechanism be effective during the PTY period only, and that Z-factor adjustments should apply when there are cost decreases, as well as potential increases.

As part of the settlement process, ORA and the Applicants filed their PTY Settlement Motion on September 11, 2015. The PTY Settlement Motion requests approval of a settlement to extend the PTY period by one year to 2019. As a result, ORA and the Applicants are seeking approval of a four year GRC rate cycle. The PTY Settlement Agreement provides that the agreement is contingent on two conditions. First, that the Commission adopt the SDG&E Settlement Motion and the SoCalGas Settlement Motion. And second, that the Commission adopt a four year GRC cycle for all the major California investor-owned utilities, and ORA and the Applicants will jointly request that relief in a petition for modification of D.14-12-025 to modify the Commission's rate case plan. ORA and the Applicants filed a joint petition on October 22, 2015 to modify the GRC cycle length that was adopted in D.14-12-025.

In the following paragraphs, we discuss the background of PTY period the Applicants' original requests, and the PTY Settlement Motion.

6.16.2. PTY Period and PTY Ratemaking Mechanism

Prior to the filing of the PTY Settlement Motion, SDG&E proposed "a three-year GRC term of 2016-2018, with its next GRC cycle beginning with [TY] 2019." (Ex. 95 at 1.) SDG&E's reasoning for the three-year GRC term was to avoid conflicts with the expected GRC filings of PG&E and SCE in 2017 and 2018, respectively.

For this two year attrition period of 2017 and 2018, SDG&E proposes a PTY ratemaking mechanism that is comprised of two components: O&M escalation, and capital additions. Using SDG&E's proposed PTY ratemaking mechanism, SDG&E estimates an attrition year revenue requirement increase of $96.6 million (5.07%) in 2017, and an increase of an additional $96.3 million (4.81%) in 2018.

The O&M escalation would make adjustments for labor and non-labor costs, and for medical costs. For the labor and non-labor costs, SDG&E proposes to use the Global Insight forecasts as described by SDG&E's escalation witness in Exhibit 305. According to Exhibit 95, the dollar escalation increase for attrition year 2017 would be effective January 1, 2017, and would be based of on Global Insight forecast available in September 2016. For the dollar escalation increase for the attrition year beginning January 1, 2018, the escalation index would be based on the September 2017 Global Insight forecast.

For the medical care adjustments to the O&M escalation, SDG&E proposes that the medical costs be increased by 7.8% in both 2017 and 2018. SDG&E's medical care adjustment is based on the actuarial forecast of Towers Watson as described in Exhibit 193.

The second component of SDG&E's PTY ratemaking mechanism is the adjustment for capital additions. This adjustment is to the capital-related revenue requirements to reflect the cost of plant additions. During the PTY period, SDG&E is proposing to adjust the rate base and the associated revenue requirements to reflect the impact of forecasted capital additions. SDG&E is not proposing to adjust the rate base elements of materials and supplies, customer advances, or working cash. SDG&E's capital additions adjustment uses "a seven-year average of historical capital additions as a proxy for future capital additions…." (Ex. 95 at 6.) To derive this seven-year average, the capital additions during this period are first escalated to 2016 dollars and then averaged. SDG&E points out that its capital additions adjustment is consistent with the approach that the Commission approved for PG&E in D.14-08-032.

To implement the PTY ratemaking mechanism, SDG&E proposes to continue the process of making these adjustments through an annual PTY advice letter filing that would take place on or before November 1. The resulting rate adjustment for the attrition year would be effective on January 1 following the filing of the advice letter.

ORA recommends in Exhibit 398 that an additional attrition year be added to the Applicants' three year GRC term. Instead of attrition years 2017 and 2018, ORA requests that the attrition years cover 2017, 2018 and 2019. ORA contends that a four year "GRC cycle allows for better utility financial and operational management of spending and investment." (Ex. 398 at 13.)

ORA is agreeable to a PTY ratemaking mechanism that provides the Applicants with some reasonable level of revenue increases for the attrition years. ORA recommends that the PTY ratemaking mechanism use a 3.5% increase factor for each of the attrition years.[91] ORA's PTY mechanism is based on the All-Urban Consumer Price Index that the Commission has used in prior GRCs, including the Applicants' last GRC in D.13-05-010. ORA notes that the recently authorized attrition increases for large energy utilities have been in the range of about 3.0% to 4.5% per year. Based on ORA's forecast of SDG&E's TY 2016 revenue requirement, the application of the 3.5% factor would result in an increase in 2017 of around $60.6 million, and in 2018 of around $62.8 million. If a third attrition year is added, ORA estimates that the increase in 2019 would be around $65 million.

As the basis for ORA's lower PTY ratemaking adjustment, ORA contends that the Applicants are not automatically entitled to PTY revenue increase. ORA notes in Exhibit 398 that prior to 1982, the Commission only adjusted the base revenue requirement during the GRC proceedings. ORA further notes that the PTY attrition rate adjustments were implemented in the early 1980s due to the high inflation and lower rates of customer growth and sales that were experienced in the late 1970s and early 1980s.

In the SDG&E Settlement Comparison Exhibit at 13, the settling parties have agreed to ORA's PTY ratemaking recommendation of a 3.5% increase in 2017, and a 3.5% in 2018.

The PTY Settlement Motion that the Applicants and ORA filed needs to be addressed at this juncture because of its PTY ratemaking impacts. The

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[91] In the event the Commission does not adopt ORA's fixed percentage increases for the attrition years, ORA recommends that its alternative PTY ratemaking mechanism (described in Exhibit 398) be adopted.

agreement reached in the PTY Settlement Agreement provides for a 2019 attrition year, and an escalation rate of 4.3% for the 2019 attrition year. The PTY Settlement Agreement is contingent on two conditions. First, the Commission needs to adopt the settlement agreements contained in the SDG&E Settlement Motion, and in the SoCalGas Settlement Motion. Second, the Commission needs to adopt a four year GRC cycle for all of the major California investor-owned utilities.

In order to effectuate the change from a three year to four year GRC cycle, ORA and the Applicants jointly filed a petition for modification of D.14-12-025 in R.13-11-006 on October 22, 2015. That petition for modification requests that D.14-12-025 be modified to change the rate case cycle from three to four years. Subsequently, on October 22, 2015, SDG&E, SoCalGas, and ORA filed in R.13-11-006 a joint petition to modify the GRC cycle length in D.14-12-025 (joint petition).

With respect to the PTY Settlement Motion, several parties filed responses in opposition to the adoption of the PTY Settlement Agreement. A joint reply to those responses was also filed. Those responses and reply have been reviewed and considered.

Several parties filed responses in opposition to the petition for modification of D.14-12-025 in R.13-11-006, and a reply to those responses was also filed.

The petition for modification of D.14-12-025 is being addressed in a separate decision in R.13-11-006. The proposed decision addressing this petition for modification is being considered at the June 9, 2016 Commission meeting. The proposed decision in R.13-11-006, which was served on the service list in R.13-11-006 on May 6, 2016, recommends that the petition for modification of

D.14-12-025 be denied. If the Commission adopts that proposed decision, then the contingencies set forth in the PTY Settlement Agreement will not be met. The PTY Settlement Agreement provides that if these two contingencies are not satisfied, "then this PTY Settlement Agreement will be deemed null and void and SDG&E and SoCalGas will proceed with filing their next GRC applications in September of 2017, as a TY 2019 GRC." (PTY Settlement Agreement at 3.)

Since this decision expects that the Commission will adopt the recommendation in the R.13-11-006 proposed decision to deny the petition for modification of D.14-12-025 to change the GRC cycle from three to four years, the PTY Settlement Agreement in the PTY Settlement Motion will be rendered null and void. Consistent with the outcome expected in R.13-11-006, this decision denies the PTY Settlement Motion to adopt the PTY Settlement Agreement.

As a result, the GRC cycle for SDG&E and SoCalGas shall remain a three-year rate cycle, and for purposes of these consolidated proceedings, the GRC cycle shall consist of TY 2016 and the attrition years of 2017 and 2018.

Having resolved the issue about the length of the GRC cycle, the next issue is to decide whether the 3.5% PTY ratemaking mechanism agreed to in the SDG&E Settlement Agreement is reasonable. As mentioned above, we have reviewed the testimony of ORA and SDG&E, and compared their recommendations to the agreed upon PTY ratemaking mechanism. We have also considered the pleadings filed in connection with the PTY Settlement Motion. Based on all those considerations, the agreed upon 3.5% PTY ratemaking mechanism is reasonable and should be adopted for each of the attrition years.

In the SDG&E Settlement Comparison Exhibit at 14, the settling parties have agreed to the "continuation of SDG&E's existing, currently authorized, Z-factor mechanism." Based on the parties' positions, and the Attachment 1

Settlement Agreement, it is reasonable to continue the Z-factor mechanism without any change during the GRC cycle, and that portion of the SDG&E Attachment 1 Settlement Agreement should be adopted. We want to emphasize that the Z-factor, as it currently stands, also applies to events that cause cost decreases, not just to events causing cost increases.

6.17. Summary of SDG&E Settlements

Except for the settling parties agreement with respect to bonus depreciation, and the SONGS offsite storage costs, we conclude that the five settlements attached to the SDG&E Settlement Motion are reasonable and in the public interest given our discussion of the original positions of the parties, in comparison to the amounts, methodologies, and other agreements set forth in the five settlements. Except as noted, the five settlements are also consistent with the law, and will provide the necessary funds to allow SDG&E to operate its electric and natural gas systems safely and reliably at reasonable rates. Accordingly, the SDG&E Settlement Motion to adopt the five settlements is granted, and the five settlements attached to the SDG&E Settlement Motion, excluding the exceptions discussed in today's decision, should be adopted.

Due to the provision in the Attachment 5 Settlement Agreement about the tax issue involving the deduction of repairs, and the adjustments we make for bonus depreciation, and the SONGS offsite storage costs, today's decision adopts a TY 2016 revenue requirement of $1,789,286,000 for the combined operations of SDG&E.

For the reasons stated earlier, the PTY Settlement Motion is denied.

7. SoCalGas A.14-11-004

7.1. Background

Prior to the filing of the SoCalGas Settlement Motion, and the PTY Settlement Motion, SoCalGas requested an updated revenue requirement for TY 2016 of $2,331,187,000.

As a result of the Attachment 1 settlement agreement to the SoCalGas Settlement Motion, the settling parties have agreed to a TY 2016 revenue requirement of $2,219,426,000.

In the sections below, we describe the various O&M costs and the capital related costs which make up the revenue requirement for SoCalGas.

7.2. Gas Distribution

7.2.1. Introduction

The gas distribution network of SoCalGas consists of about 50,400 miles of gas main pipelines that operate at either high pressure or medium pressure. The gas distribution network is also made up of about 49,000 miles of service lines. These lines are made up of various diameters, and are constructed of both steel and plastic. There are also associated gas distribution facilities such as valves and regulators.

7.2.2. O&M Costs

As shown at line 4 of SoCalGas' summary of earnings table, SoCalGas requested updated O&M costs of $144.989 million for gas distribution.[92] ORA

[92] The summary of earnings table can be found at page 283 of the SoCalGas Settlement Comparison Exhibit. The SoCalGas Settlement Comparison Exhibit is appended to Attachment 1 of the SoCalGas Settlement Motion.

had proposed that the O&M costs for gas distribution be set at $126.701 million. The SoCalGas Settlement Agreement agrees to $134.887 million in O&M costs.

The gas distribution O&M costs consist of various activities to operate and maintain SoCalGas' pipelines and associated equipment in good working order in order to provide safe and reliable gas service to all of its customers who use natural gas. According to SoCalGas, this work is performed by a trained and skilled workforce, and includes construction crews, technical planners, and engineers. There are about 1700 gas distribution employees, who operate out of four operating region headquarter facilities and 52 operating bases. SoCalGas contends that the "level of funding requested in this testimony will allow compliance with pipeline safety regulations and the continued safe and reliable operation of SoCalGas' gas distribution pipeline system." (Ex. 58 at 13.) In addition, all of these activities are consistent with the directives in Pub. Util. Code §§ 961 and 963 to develop and implement a plan for the safe and reliable operation of its gas pipelines, and to place the safety of the public and gas corporation employees as the top priority.

In preparing the forecasts of these costs, SoCalGas reviewed historical spending levels, assessed future requirements for gas service, and considered the underlying cost drivers for the different kinds of activities. According to SoCalGas, its forecasted level of funding will provide "the necessary resources to continue to manage the gas distribution system through business and operational challenges, and will continue to provide safe and reliable natural gas service at reasonable cost." (Ex. 58 at 4.)

Many of the gas distribution O&M costs relate to ensuring the safety and reliability of SoCalGas' gas operations. According to SoCalGas, it "actively evaluates the condition of its pipeline system through maintenance and operations activities, and replaces pipeline segments to preserve the safe and reliable system customers expect." (Ex. 58 at 4.) These activities include such things as: performing leak surveys; evaluating and repairing main and service leaks; locating and marking facilities to avoid third party damage; and replacement of aging pipelines and associated equipment.

ORA's recommended amount of $126.772 million for the gas distribution O&M costs is lower than the recommended amount of SDG&E. As described in Exhibit 350, ORA's amount is lower because of ORA's belief that SoCalGas did not provide adequate support for its request, and because ORA used more appropriate methodologies.

The agreed upon gas distribution O&M costs represents a compromise of the gas distribution costs that SoCalGas and ORA had proposed. None of the other settling parties to the SoCalGas Settlement Motion oppose the gas distribution costs that were agreed upon. In addition, none of the parties who filed comments on the SoCalGas settlement motion, or who have filed briefs, oppose the gas distribution O&M costs.

Based on the testimony of the witnesses for SoCalGas and ORA regarding the gas distribution costs, the agreed upon settlement amount of $134.887 million for the O&M costs is reasonable and should be adopted. This amount will provide the necessary funding for SoCalGas to carry out the daily O&M activities to operate the gas distribution system in a safe and reliable manner.

7.2.3. Capital Expenditures

According to SoCalGas, the capital expenditure activities for gas distribution respond to the operational, maintenance, and construction needs. The work activities associated with the gas distribution capital expenditures are performed daily, and are based on a variety of risk factors and work drivers. The work elements are prioritized based on a "review of maintenance activities and findings, results of field workforce inspections, and records of condition." (Ex. 58 at 8.) Such projects include: expanding the current system in order to provide service to new customers and to meet the growth in load; improving system pressure to maintain system reliability and safety; to accommodate customer and/or load growth; replacing aging pipelines and facilities; and relocation of pipelines and associated facilities to accommodate the needs of local and state agencies.

As described in Exhibit 58, for the capital expenditures associated with gas distribution, SoCalGas requested the following capital expenditures: 2014 - $274.426 million; 2015 - $271.848 million; and 2016 - $273.616 million. (See Exhibit 58.)

In Exhibit 350, ORA proposed that the capital expenditures for gas distribution be set at the following: 2014 - $247.447 million; 2015 - $239.391 million; and 2016 - $273.616 million.

In the SoCalGas Settlement Comparison Exhibit at 10, the settling parties agree to the following gas distribution capital expenditures: ORA's recommended 2014 amount of $247.447 million, instead of SoCalGas' recommended amount of $274.426 million; SoCalGas' 2015 recommended amount of $271.848 million; and SoCalGas' 2016 recommended amount of $273.616 million.

None of the parties have questioned the agreed upon amounts for the gas distribution capital expenditures. Based on the testimony of the witnesses for SoCalGas and ORA, the amounts recommended for the gas distribution capital expenditures are reasonable because they provide sufficient funds to enable SoCalGas to continue to provide safe and reliable gas distribution service.

Accordingly, the following amounts for the gas distribution capital expenditures, as set forth in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, should be adopted: 2014 - $247.447 million; 2015 - $271.848 million; and 2016 - $273.616 million.

7.3. Gas Transmission

7.3.1. Introduction

SoCalGas' gas transmission unit is responsible for the operation and maintenance of about 2972 miles of high pressure pipeline, and eleven compressor stations. Under the federal definition of transmission pipelines, about 3509 miles of pipeline is operated by SoCalGas' gas distribution and gas transmission units. The gas transmission system of SoCalGas is designed to receive natural gas from interstate pipelines and from various California offshore and onshore production sources. That gas is monitored for gas quality, and is then delivered into SoCalGas' gas distribution system, underground gas storage fields, and to some non-core customers.

The gas transmission system of SoCalGas is designed to receive 3.875 Bcf per day of interstate and intrastate gas supplies at its receipt points on a firm basis. According to SoCalGas, with a combination of pipeline receipts and withdrawal from gas storage, the transmission system is capable of sending out up to six Bcf per day of gas to customers.

7.3.2. O&M Costs

The O&M costs consist of the day-to-day expenses to safely operate and maintain SoCalGas' gas transmission system. As described in SoCalGas' testimony in Exhibit 35, these expenses are associated with pipeline operations, gas compression operations, and field engineering and technical support services. At line 5 of SoCalGas' summary of earnings table, SoCalGas had requested updated O&M costs of $40.867 million for gas transmission. This represents an increase of $8.374 million over the 2013 adjusted-recorded costs.

SoCalGas' request for the TY 2016 O&M costs for gas transmission are based on increased regulatory requirements and changes in SoCalGas' policy relating to the maintenance and enhancement of the integrity of the transmission pipeline system. According to SoCalGas, these additional costs are attributable to some of the following: the escalating pipeline safety fee to PHMSA; the pipeline lease agreement with the City of Long Beach; the workload increase in the Oxnard Pipeline District; knowledge management and succession staffing; pipeline district workload increase; expansion of the operator qualification program to demonstrate proficiency in various tasks; providing communication and field staff to meet first responder interaction requirements; enhancements to the cathodic protection system; change in leakage survey policy; obtain aerial leak detection equipment; additional clerical workload due to new incremental fieldwork activities; security upgrades at critical facilities; specialized skill set training; incremental O&M costs associated with post-PSEP activities; maintenance compliance for pipeline valve and infrastructure; additional funding to support work regarding the compressor stations; and additional funding to support the work of field engineering and technical support.

As described in Exhibit 379, ORA recommended that the O&M costs for gas transmission be set at $39.569 million.[93] ORA's proposed reduction is primarily based on the lower costs for certain non-shared costs, and on the lower recorded 2014 cost for shared costs.

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[93] Due to rounding, SoCalGas' summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion shows O&M costs of $39.568 million.

In the SoCalGas Settlement Comparison Exhibit at 7, the settling parties have agreed to O&M costs for gas transmission of $40.877 million.

Based on the testimony of SoCalGas and ORA on the O&M costs for gas transmission, it is reasonable to adopt the agreed upon O&M costs contained in the SoCalGas Settlement Agreement. Such an amount will provide SoCalGas with sufficient funds to safely and reliably operate its gas transmission system. The O&M amount of $40.877 million for gas transmission should be adopted.

7.3.3. Capital Expenditures

The SoCalGas Settlement Comparison Exhibit at 11 combines the capital expenditures for its gas transmission and gas engineering. For that reason, we discuss these capital expenditures together in this section, rather than separately. Also, the capital expenditures associated with SoCalGas' TIMP and DIMP are discussed in the Engineering section of this decision.

SoCalGas requested the following capital expenditures for gas transmission and gas engineering: 2014 - $64.102 million; 2015 - $103.795 million; and 2016 - $141.595 million. (See Ex. 25 at 50.)

According to SoCalGas, the capital expenditures for gas transmission are for "projects to enhance the efficiency and responsiveness of our operations, facilitate compliance with applicable regulatory and environmental regulations and support Gas Transmission and Storage operations to provide safe and reliable delivery of natural gas to customers at reasonable cost." (Ex. 25 at iv.) As described in SoCalGas' testimony, these activities include the costs associated with the following: install new transmission pipelines; replacement and relocation of pipelines; maintaining and replacing key components of the compressor station-related equipment; installation of cathodic protection to preserve the integrity of transmission pipelines from corrosion; replacing meter and regulator equipment; install or upgrade auxiliary equipment; securing the necessary land rights; building and replacement of storage and buildings to protect equipment; purchase of laboratory equipment; acquiring and replacing high-value tools that are used on transmission pipelines; and supervision and engineering pool.

ORA reviewed SoCalGas' capital expenditure forecast for 2014, 2015, and 2016. ORA also reviewed SoCalGas' recorded capital expenditures for 2014. ORA recommended in Exhibit 379 that the capital expenditures for gas transmission and gas engineering be set at the following: 2014 - $47.059 million; 2015 - $86.881 million; and 2016 - $145.756 million. The 2014 amount is based on the actual-recorded amount. ORA's recommended amount for 2015 is lower than SoCalGas' recommended amount, while ORA's 2016 amount is higher than SoCalGas' amount. As described in Exhibit 379, these differences are due to ORA's use of different methodologies than what SoCalGas used.

In the SoCalGas Settlement Comparison Exhibit at 11, the settling parties agree to the adoption of the following capital expenditures for gas transmission and engineering: 2014 - $47.059 million; 2015 - $98.662 million; and 2016 - $146.730 million.

Based on the testimony of SoCalGas and ORA concerning the gas transmission and gas engineering capital expenditures, the agreed upon amounts in the SoCalGas Settlement Agreement are reasonable. The capital expenditures set forth in the SoCalGas Settlement Agreement will provide sufficient funds to perform the engineering and transmission work described in SoCalGas' testimony, so that SoCalGas' gas transmission system can continue to transport natural gas in a safe and reliable manner. Accordingly, the following gas transmission and gas engineering capital expenditures should be adopted: 2014 - $47.059 million; 2015 - $98.662 million; and 2016 - $146.730 million.

7.4. Underground Storage

7.4.1. Introduction

SoCalGas owns and operates four underground gas storage fields in its service territory. The purpose of these storage fields is to store natural gas in underground geological formations for SoCalGas' core customers and for SoCalGas' gas storage customers who inject and withdraw gas based on their needs, and for daily gas balancing requirements.

These four storage fields have a combined working capacity of about 136 Bcf. These fields are: Aliso Canyon (86.2 Bcf); Honor Rancho (26 Bcf); La Goleta (21.5 Bcf); and Playa del Rey (2.4 Bcf). These storage fields play an important role in storing gas for future use, and are part of the integrated natural gas infrastructure that is used by SoCalGas "to provide southern California businesses and residents with safe and reliable energy and gas storage services at a reasonable cost." (Exhibit 45 at 3.) The Aliso Canyon underground gas storage facility provides about 63.3% of SoCalGas' gas storage capacity.

The natural gas that is injected into these storage fields is compressed onsite at very high pressures, and then injected into the underground storage fields through piping networks and storage wells. The injection season typically occurs during seasonal periods (late spring and summer) when gas consumption is low, and ample gas supplies are available. This gas is then usually withdrawn and delivered to customers when gas consumption is high, usually during the winter months.[94] According to SoCalGas, "At the beginning of the withdrawal season in November, the combined storage capacity of the four storage fields is enough to supply all of SoCalGas' customers for approximately six weeks, if one assumes an average daily consumption rate." (Exhibit 45 at 2.)

SoCalGas' storage department is responsible for the operation, maintenance, integrity, and engineering functions associated with the use of the gas storage wells, and injection and withdrawal facilities. This department has about 175 employees. The routine O&M activities for underground gas storage consist of the following: the administrative and engineering costs of operating the facilities on a daily basis, including training in the areas of leadership, safety, technical, operator qualification, and quality assurance; the costs associated with the routine operation of the storage reservoirs, including well testing and pressure surveys, and wellhead and down-hole activities; the costs of maintaining the gas compressors and other mechanical equipment; the costs of maintaining the structures for compressor stations, and rents and royalties; and the costs associated with maintaining records for storage assets and operations.

The O&M costs for SoCalGas' underground storage activities are shown at line 6 of SoCalGas' summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion. SoCalGas requested $40.182 million for the O&M costs for underground storage. ORA recommended underground storage O&M costs of $36.375 million.

In the SoCalGas Settlement Comparison Exhibit at 7, the settling parties have agreed to the amount of $38.381 million for the underground storage O&M

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[94] According to the SoCalGas storage witness, the storage fields are oftentimes being used to inject and withdraw gas on a daily basis for electric generation needs. (13 R.T. 1083-1085, 1073.)

costs for TY 2016. At page 11 of the SoCalGas Settlement Comparison Exhibit, the settling parties have agreed to the following capital expenditure amounts for underground storage: 2014 - $71.069 million; 2015 - $74.270 million; and 2016 - $90.523 million.

7.4.2. Aliso Canyon Leak

The SoCalGas Settlement Motion was entered into and filed by the parties on September 11, 2015. The filing of the SoCalGas Settlement motion took place about six weeks before the natural gas stored at Standard Sesnon Well 25 (SS-25 well) of the Aliso Canyon underground gas storage facility began to leak into the atmosphere on or about October 23, 2015. The leakage of the natural gas from Aliso Canyon resulted in the evacuation of residents living near the storage field in a neighborhood known as Porter Ranch. In November and December of 2015, the DOGGR directed SoCalGas to cease injecting natural gas into the Aliso Canyon storage field.[95]

On January 6, 2016, Governor Brown declared an emergency with respect to the leakage of natural gas at the Aliso Canyon storage facility. Among other things, the proclamation directs the Commission that SoCalGas "cover costs related to the natural gas leak and its response, while protecting ratepayers."

The Governor's proclamation also states that the Commission and the Energy Commission, "in coordination with the California Independent System Operator, shall take all actions necessary to ensure the continued reliability of

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[95] On May 10, 2016, the Governor signed SB 380 into law. (Statutes of 2016, Chapter 14.) Among other things, that law, which took immediate effect, continues the prohibition against injecting any natural gas into the Aliso Canyon storage fields until a comprehensive review of the safety of the gas storage wells at Aliso Canyon is completed.

natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Storage Facility."

The leakage from the SS-25 well at Aliso Canyon was sealed on or about February 18, 2015.

None of the settling parties to the SoCalGas Settlement Motion, and none of the other parties to this proceeding, have filed any pleading in these proceedings seeking to revise the agreed upon settlement amounts for SoCalGas' underground gas storage activities.

The situation at Aliso Canyon requires that the Commission scrutinize the O&M costs and capital expenditures that SoCalGas originally requested for its underground storage activities, and the O&M costs and capital expenditures agreed to in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion. This heightened scrutiny is needed because of the planned activities that SoCalGas proposes to take as part of this GRC cycle, the impact of the Aliso Canyon leak on SoCalGas' planned activities, and the fiscal impact on ratepayers of the planned O&M and capital expenditures during this GRC cycle.[96]

One of the planned activities that SoCalGas proposed prior to the Aliso Canyon leak, is to undertake during this GRC cycle a more proactive and in-depth approach for evaluating and managing the risks associated with the wells in SoCalGas' underground storage fields. According to SoCalGas, in the past it has historically managed the risk at its storage facilities "by relying on more traditional monitoring activities and identification of potential component

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[96] See Section 6.11.3. of this decision for a discussion about what needs to occur before any variable incentive compensation for activities related to SoCalGas' underground gas storage facilities or at Aliso Canyon is awarded.

failures…." (Ex. 45 at 5.) SoCalGas further states that "Historically, safety and risk considerations for wells and their associated valves and piping components have not been addressed in past rate cases to the same extent that distribution and transmission facilities have been under the Distribution and Transmission Integrity Management Programs." (Ex. 45 at 5.) SoCalGas proposes to institute a new approach, which it refers to as the SIMP. The SIMP is modeled after the TIMP and the DIMP.

The Commission has already taken steps for SoCalGas to separately account for the costs associated with the Aliso Canyon leak. In a letter to SoCalGas dated December 23, 2015, the Commission's Executive Director directed SoCalGas to, among other things, "track all costs associated with [SoCalGas'] actions related to the leaking well at the Aliso Canyon Natural Gas storage field, including, but not necessarily limited to: efforts to stop the leak, relocations of community members and schools, litigation expenses, replacement fuel/fuel loss and emergency response."

Then in D.16-03-031, the Commission ordered SoCalGas "to establish a memorandum account, effective immediately, to track SoCalGas's authorized revenue requirement and all revenues that SoCalGas receives for its normal, business-as-usual costs to own and operate the Aliso Canyon gas storage field." (D.16-03-031 at 8.) The tracking of such costs excludes the "expenses associated with the recent gas leak at Aliso Canyon." Ordering Paragraph 3 of that decision also stated that "The Commission will determine at a later time whether, and to what extent, the tracked authorized revenue requirement and revenues should be refunded to [SoCalGas'] customers with interest."

We discuss these issues raised by the Aliso Canyon below.

7.4.3. O&M and Capital Expenditures

We first address the O&M costs for underground gas storage as reflected in Attachment 1 to the SoCalGas Settlement Motion. SoCalGas requested $40.181 million for O&M costs, while ORA requested $36.375 million. In the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, the settling parties have agreed on $38.381 million.

As described in Exhibit 45, the O&M costs for underground storage consist of three activities. The first is routine underground storage activities, which are common activities performed on a regular basis. These activities include such things as the following: management, training, and engineering costs of operating these fields; the studies needed to maintain the integrity of these facilities; the costs of routinely operating and maintaining these facilities and conducting tests and surveys; performing maintenance on the compressors and other mechanical equipment; the cost of structural improvements, and paying of rents and royalties; and maintaining the necessary records.

The second O&M activity for underground storage is the costs associated with NERBA. These costs involve compliance with the reporting requirements of the Environmental Protection Agency for emissions monitoring.

The third category of O&M activity for underground storage is the costs associated with the SIMP. SoCalGas proposes to establish the SIMP, which according to SoCalGas is a more proactive and in-depth approach for evaluating and managing the risks associated with the wells in its underground storage fields. Instead of relying on traditional monitoring activities and identifying potential component failures, the SIMP is designed to collect more comprehensive data about all of SoCalGas' storage wells. This system data will then be "maintained and modeled to identify the top risks throughout Storage."

(Exhibit 45 at 6.) This will be accomplished by moving away from the current method of risk assessment which relies on a qualitative assessment. This qualitative assessment is based on SoCalGas' lengthy experience in operating and managing its gas storage facilities. SoCalGas states that "The future of risk assessment for our storage system is moving towards a more robust and quantitative approach that will help us capture more information on the condition of our storage wells and develop models that will assist in prioritizing risk mitigation activities." (Exhibit 45 at 6.[97]) The models that are developed from the well data will be used to evaluate threats and risks on the storage system, and will enable SoCalGas to prioritize those threats based on location, age, condition, and other factors. The assessment of the wells is to provide SoCalGas with additional confidence that the "wells, down-hole equipment, and associated pipe laterals maintain their compliance with DOGGR regulations." (Exhibit 45 at 18.) SoCalGas goes on to state:

> While SoCalGas currently meets existing requirements under DOGGR regulations, the possibility of a well related incident still exists, given the age of the wells and their heavy utilization. A SIMP will further decrease risk always present in these types of operations, provide a higher level of safety for its customers and employees, and further protect the environment. (Exhibit 45 at 18.)

In describing the difference between SoCalGas' management of the risks at its storage fields prior to the proposed SIMP, the storage witness testified that well inspections have been part of SoCalGas' previous GRC funding requests. The SIMP is different from the well inspections that have been done in the past

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[97] SoCalGas notes in Exhibit 45 that many of the underground storage wells date back to the 1940s, and that the average age of the wells is 52 years.

because the SIMP is attempting to get a step ahead by evaluating available information in advance of a problem that could occur, instead of operating in a reactive maintenance mode that relies on information that may indicate an abnormal operating condition. (See 13 R.T. 1000-1001.)

SoCalGas anticipates that the SIMP will last for six years, which is the length of time that it will take to inspect all of the wells and to mitigate any identified conditions. After this six-year period, the future inspection and mitigation costs will be addressed as part of SoCalGas' routine operations.

For TY 2016, SoCalGas' O&M request for underground storage includes $5.676 million for the SIMP activities. SoCalGas requests that the SIMP O&M costs receive two-way balancing account treatment due to the uncertainty in inspection costs, the unknown number of at-risk wells, and the degree of repair work that may be needed. In TY 2016, SoCalGas estimates that the SIMP-related capital expenditures will be about $24.272 million.

ORA supports SoCalGas' SIMP proposal, and views it as an innovative approach of improving the safety and integrity of the underground gas storage facilities. ORA does not oppose the proposed costs for NERBA and the SIMP. However, instead of a two-way balancing account for the SIMP costs, ORA recommends a one-way balancing account. With respect to the routine underground storage costs, ORA recommends that the amount be reduced due to the drop in historical spending from 2012 to 2014. Thus, ORA recommended that the O&M amount for underground storage be set at $36.375 million instead of SoCalGas' amount of $40.181 million.

The UWUA, which represents many of SoCalGas' employees, supports the proposed SIMP activities. UWUA supports the funding of the SIMP at SoCalGas' proposed amount, and recommends expanding the amount if possible. UWUA states that the "SIMP addresses pipe and facilities in the storage field that is outside the scope of the federal/state rules for the existing" TIMP, and that the SIMP "is a very important innovation that UWUA fully supports." (Exhibit 320 at 8.) In Exhibit 324 at 5, the UWUA witness states that the SIMP "is a valuable addition to the SoCalGas storage field management process." The UWUA witness also notes that the condition of the underground storage facilities "are aging and in need of significant replacement and upgrade, particularly valves, engines and compressors." (Exhibit 324 at 3.)

In Exhibit 324, UWUA recommends that a working group composed of UWUA, SoCalGas management, and Commission staff, be established to coordinate and clarify the SIMP activities.

In Exhibit 347, UCAN originally opposed SoCalGas' request for a two-way balancing account for the SIMP costs due to the concern that SoCalGas would be allowed to recover funds in excess of the amount authorized.

After hearings concluded, TURN and UCAN agreed with SoCalGas to establish a two-way balancing account for the SIMP expenditures with recovery procedures similar to the TIMP and DIMP. This is reflected in the Attachment 5 settlement agreement that is appended to the SoCalGas Settlement Motion. That provision of the Attachment 5 settlement agreement provides as follows:

> SoCalGas will establish a two-way balancing account for SIMP expenditures. The advice letter process for recovery of any undercollections will be limited to undercollection amounts up to 35% of the 2016 GRC cycle total SIMP revenue requirement and will require a Tier 3 advice letter. Any amounts above the 35% will be subject to a separate application procedure.

In Exhibit 48, SoCalGas provided rebuttal testimony to the various points raised by ORA, UWUA, and UCAN.

It should be noted that DOGGR has regulatory jurisdiction over the well, and any of the valves and pipe between the withdrawal well and the withdrawal valves. The Commission has jurisdiction over the above ground pipes which interconnect to the pipes and valves which inject and withdraw the gas from the underground storage fields. However, all of the cost activities associated with the operation and maintenance of SoCalGas' underground gas storage facilities are recovered through the GRC process, including SoCalGas' proposed SIMP.

Based on a review of the testimony of SoCalGas, ORA, UCAN, and UWUA, as well as the SoCalGas Settlement Agreement in Attachment 1 of the SoCalGas Settlement Motion, the agreed upon amount of $38.381 million for the underground gas storage O&M costs is reasonable. This amount is reasonable because it allows SoCalGas sufficient funds to continue to operate and maintain its underground gas storage facilities, to meet its reporting requirements, and to institute its SIMP to proactively detect potential problems with its gas storage facilities.

Although the Aliso Canyon leak occurred during the time SoCalGas' request for the SIMP in SoCalGas' TY 2016 GRC proceeding was pending, the request for the SIMP activities is reasonable due to need to better assess the potential risks of another leak occurring. The proposed SIMP will allow SoCalGas to gather more well data, and to better inspect, manage and predict possible risks. This type of incremental activity comes at a cost, and the agreed upon amount of $38.381 million is an increase of $8.307 million over the 2014 recorded O&M costs of $30.074 million. The $38.381 million is also represents a compromise between the $36.375 million that ORA recommended, and the $40.181 million that SoCalGas requested. Accordingly, the agreed upon O&M costs of $38.381 million should be adopted for underground storage.

With respect to the capital expenditures, ORA recommended in its testimony that the recorded 2014 capital expenditures of $71.069 million be used instead of SoCalGas' requested amount of $71.429 million. ORA did not oppose SoCalGas' request of $74.270 million and $90.523 million, for the 2015 and 2016 capital expenditures, respectively. Except for the settlement in Attachment 5 of the SoCalGas Settlement Motion addressing the balancing account treatment for the SIMP expenditures, none of the other parties have questioned the capital expenditures for underground storage.

Based on the testimony of SoCalGas, ORA, and UWUA, and the settlement in Attachment 1 of the SoCalGas Settlement Motion concerning the agreed upon amount of the capital expenditures, the agreed upon capital expenditures for underground storage are reasonable. The capital expenditures will provide sufficient monies for SoCalGas to maintain, replace, and to upgrade the various components which make up the underground gas storage facilities. In addition, such funding will allow SoCalGas to take a more proactive approach to manage, identify, diagnose, and mitigate potential safety and integrity problems associated with the gas storage wells. Accordingly, the following capital expenditures for underground storage should be adopted: 2014 - $71.069 million; 2015 - $74.270 million; and 2016 - $90.523 million.

Funding the underground storage O&M costs and capital expenditures at these levels will ensure that the facilities are being maintained in good working order, and that the SIMP is carried out. All of those maintenance, mitigation, and preventative activities described in SoCalGas' testimony should enable it to prevent a similar leak from occurring in the future at its underground storage facilities.

The settlement agreement in Attachment 5 of the SoCalGas Settlement Motion provides in part that for the SIMP expenditures, SoCalGas will establish a two-way balancing account for actual SIMP expenditures. The Attachment 5 settlement agreement provides for the establishment of a Tier 3 advice letter process to recover any undercollection amounts up to 35% of the 2016 GRC cycle total SIMP revenue requirement. Any undercollected amounts above the 35% will require a separate application. Any unused funds will be returned to the ratepayers.

No one contests the two-way balancing account procedure set forth in the Attachment 5 settlement agreement of the SoCalGas Settlement Motion. Although ORA recommended in its testimony that a one-way balancing account be established for the SIMP expenditures, ORA is a party to the SoCalGas Settlement Motion. As a party to the SoCalGas Settlement Motion, ORA requests that the Attachment 5 settlement agreement also be approved.

With respect to whether the SIMP expenditures should be subject to a one-way or a two-way balancing account, we are persuaded that a two-way balancing account should be established. As SoCalGas points out, the costs of inspecting and remediating potential problems at the underground storage facilities may vary. In order to remediate potential problems at other wells, more monies than what the parties agreed to may be necessary. Accordingly, the provision in the Attachment 5 settlement agreement to institute a two-way balancing account procedure for the SIMP expenditures is reasonable, and that provision of the Attachment 5 settlement agreement should be adopted.

As for UWUA's recommendation for a working group to discuss and implement the SIMP activities, we are not persuaded that a working group is needed. SoCalGas' management has plenty of experience with its underground storage facilities. SoCalGas should value the input of its field employees with regard to the SIMP activities, but we will not require that a working group of UWUA members and Commission staff be formed to assist SoCalGas with the development and implementation of the SIMP.

As for the issues raised by the Aliso Canyon leak, and whether the Commission should be opening other proceedings to address these issues, it is not appropriate to explore those issues in the context of this proceeding. This GRC proceeding is looking at the funding needs over the GRC cycle, and is not focusing into what may have caused the Aliso Canyon leak, and whether authorized underground storage expenditures in the past should have prevented the leak from occurring.[98]

Currently, the Commission's SED is investigating the causes of the well leakage at Aliso Canyon. Until that report is finished, it is premature for the Commission to open an Order Instituting Investigation into the causes of the Aliso Canyon leakage, whether past expenditures were appropriately spent to detect these kinds of problems, and whether SoCalGas' ratepayers should bear any responsibility for the various costs incurred as a result of the leakage at Aliso Canyon. Those are all issues that should be examined in a future proceeding.

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[98] We note that in SoCalGas' TY 2012 GRC in D.13-05-010, the Commission approved and authorized a revenue requirement for 2012 through 2015 that included a TY 2012 budget of $28.939 million for O&M activities for its underground gas storage facilities (which was escalated for attrition years 2013, 2014 and 2015), and capital expenditures of $27.660 million in 2010, $31.605 million in 2011, and $30.596 million in 2012. Escalation of the capital expenditures was also provided for D.13-05-010. As part of those capital expenditures, SoCalGas planned to replace existing aging, and mechanically unsound wells, and to drill replacement wells. This was expected to make up $7.019 million in capital expenditures for 2010, 2011 and 2012. (See D.13-05-010 at 374-375.)

As noted earlier, the Commission has already taken steps to have SoCalGas separate out the costs attributable to the Aliso Canyon leak, and all the expenses and revenues that SoCalGas would normally incur as a result of the normal day-to-day operations of Aliso Canyon. As noted in D.16-03-031, the Commission plans to establish a procedure or proceeding to address whether normal, business-as-usual costs and revenues associated with Aliso Canyon should be refunded to ratepayers. Such a procedure or proceeding reassures us that if all or parts of Aliso Canyon are shut down for all or some portion of the TY 2016 GRC cycle, that the amounts for underground storage activities authorized in today's decision will not be diverted for other uses. If some or all of the Aliso Canyon storage wells are shut down during any part of the TY 2016 GRC cycle, the memorandum account established pursuant to D.16-03-031 will allow the Commission to track, and make subject to refund, any unspent amounts that are targeted for underground storage activities.

To ensure that the costs associated with the leak at the SS-25 well at Aliso Canyon do not impact the costs requested in the future SoCalGas GRCs, we will require SoCalGas, as part of its next GRC filing, to provide a separate itemization of all of the costs related to the gas leak at the SS-25 well at Aliso Canyon, as well as testimony on whether the costs attributable to the Aliso Canyon leak have affected in any way SoCalGas' funding request for its underground gas storage facilities.

7.5. Engineering

7.5.1. O&M Costs

The gas engineering costs shown at line 7 of the SoCalGas summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion shows a settlement amount of $131.283 million. The cost components which make up this line item consist of gas engineering costs, and the TIMP and DIMP costs. (See Exhibit 218, Table KN-6.)

For the O&M costs associated with SoCalGas' gas engineering, SoCalGas requested updated O&M costs of $131.284 million for gas engineering. The cost components which make up this line item consist of the following: gas engineering of $34.130 million; and total TIMP and DIMP of $97.154 million.

ORA proposed that the O&M costs for gas engineering be set at $126.198 million. The SoCalGas Settlement Agreement agrees to $131.283 million in O&M costs.

The gas engineering O&M costs consist of various activities that result in providing technical guidance to support the day-to-day functions for pipeline integrity, gas transmission, and gas distribution. According to SoCalGas, these gas engineering activities consist of the following: creating and issuing policies and standards that help establish and validate compliance with applicable laws, regulations and internal policies; providing and issuing engineering designs primarily for gas transmission and gas distribution projects; and making capital investments that support the safety and reliability of the transmission system.

In preparing the forecasts of these costs, these costs support SoCalGas' "goal to continually enhance pipeline safety and help maintain reliability by making necessary and prudent investments," including adding resources for quality assurance and quality control systems. (Ex. 25 at 5.) In addition, gas engineering utilizes a process hazard analysis to identify and re-engineer out potential hazards. Gas engineering also includes costs to mitigate the risks with the integrity of the infrastructure, system reliability, and physical security.

As mentioned above, the line item for gas engineering includes the O&M costs for the TIMP and the DIMP. These two pipeline integrity management programs focus on identifying and addressing the risks to transmission and distribution pipelines as required by the Code of Federal Regulations. Both the TIMP and DIMP require that assessments and evaluations of these pipelines take place on a regular basis.

For the TY 2016 O&M cost for the TIMP, SoCalGas requested that the amount of $55.027 million be adopted. The O&M activities for the TIMP include the following: performing threat identification and risk assessment; creating and maintaining an assessment plan; performing assessments; taking remedial action; evaluating and taking additional preventative and mitigation measures; managing the GIS information flow; and addressing audit and reporting needs.

For the TY 2016 O&M cost for the DIMP, SoCalGas requested that $42.127 million be adopted. The O&M activities for the DIMP include the following: understanding of the attributes of the distribution system; identifying threats and performing risk assessments; developing programs and activities to address risks; managing the GIS information flow; and carrying out compliance, auditing, and reporting functions.

ORA did not oppose SoCalGas' request for O&M TIMP costs of $55.027 million, and the DIMP costs of $42.127 million. However, ORA recommended that the gas engineering O&M costs be set at $29.044 million, instead of SoCalGas' requested amount of $34.130 million. ORA's reduction is due to the actual recorded 2014 O&M costs for gas engineering.

The agreed upon gas engineering O&M costs represents a compromise of the gas engineering costs that SoCalGas and ORA had proposed. None of the other settling parties to the SoCalGas settlement motion oppose the gas engineering costs that were agreed upon. In addition, none of the parties who filed comments on the SoCalGas Settlement Motion, or who have filed briefs, oppose the gas engineering O&M costs.

Based on the testimony of the witnesses for SoCalGas, and ORA on the gas engineering costs, the agreed upon settlement amount of $131.283 million for the O&M costs is reasonable. This amount is the same as what SDG&E had requested in its application, and recognizes the work needs related to the TIMP and DIMP costs. This amount will provide the necessary funding for SoCalGas to carry out the daily gas engineering O&M activities to support the safe and reliable operation of the gas transmission and gas distribution systems. Accordingly, the gas engineering cost of $131.283 million should be adopted.

As discussed earlier, in the Attachment 5 Settlement Agreement of the SoCalGas Settlement Motion, TURN, UCAN, and the Applicants agreed that SoCalGas will continue to maintain separate two-way balancing accounts for the TIMP and DIMP expenditures, and agreed on the process for recovery of undercollected amounts.

Based on the reasons stated earlier for SDG&E, it is reasonable to continue the two-way balancing account treatment for the TIMP and DIMP costs, and to establish a procedure to recover the undercollected amounts. This portion of the Attachment 5 Settlement Agreement should be adopted.

7.5.2. Capital Expenditures

This section of the decision addresses the capital expenditures associated with SoCalGas' TIMP and DIMP.[99]

[99] Since the Attachment 1 settlement agreement of the SoCalGas Settlement Motion grouped the capital expenditures for gas transmission and gas engineering as single amounts, we have

Footnote continued on next page

In Exhibit 49, SoCalGas requested the following capital expenditures for TIMP and DIMP: 2014 - $53.042 million; 2015 - $48.637 million; and 2016 - $125.184 million. ORA proposed in Exhibit 379 that the capital expenditures for TIMP and DIMP be set at the following: 2014 - $51.155 million; 2015 - $48.637 million; and 2016 - $125.184 million. In the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, the settling parties recommend adoption of the following capital expenditures: 2014 - $51.155 million; 2015 - $48.637 million; and 2016 - $125.184 million.

The work activities associated with the TIMP and DIMP capital expenditures are performed on a continuing basis. These activities evaluate the transmission and distribution pipeline systems through data gathering and inspections, and then action is taken to mitigate or remediate the identified risks. According to SoCalGas, these capital expenditures support SoCalGas' "core goals of providing safe and reliable service at reasonable cost." (Ex. 49 at 21.)

According to ORA's testimony in Exhibit 379, it reviewed SoCalGas' TIMP and DIMP capital expenditure forecasts for 2014, 2015, and 2016. ORA also reviewed SoCalGas' recorded capital expenditures for 2014. ORA's testimony also recognized that the DIMP capital expenditures for 2016 are higher due to SoCalGas' plan to replace early vintage steel and plastic distribution lines more rapidly. ORA recommended in its testimony that the recorded 2014, and the 2015 and 2016 forecasts of SoCalGas, be adopted.

Based on the testimony of SoCalGas and ORA concerning the TIMP and DIMP capital expenditures, the agreed upon amounts in the SoCalGas Settlement

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addressed the capital expenditures for gas engineering and transmission in the gas transmission section of this decision. (See SoCalGas Settlement Comparison Exhibit at 11.)

Agreement are reasonable, as it will provide sufficient funds to perform the work required by the TIMP and DIMP. Accordingly, the following TIMP and DIMP capital expenditures should be adopted: 2014 - $51.155 million; 2015 - $48.637 million; and 2016 - $125.184 million.

7.6. Procurement

As shown on line 9 of SoCalGas' summary of earnings table, the settling parties have agreed upon the amount of $3.993 million for O&M gas procurement costs. (See SoCalGas Settlement Comparison Exhibit at 283.) This is the same amount that SoCalGas requested in its gas procurement testimony in Exhibit 119.

The O&M costs are incurred by SoCalGas' Gas Acquisition Department, which is responsible for the procurement of natural gas for the core customers of SDG&E and SoCalGas.[100] The Gas Acquisition Department consists of five functional groups that engage in the following activities: physical gas trading; risk management/financial trading; gas scheduling; economic analysis; and back office and IT support. As part of its daily activities, the Gas Acquisition Department performs the following: procures the natural gas by entering into contracts and making other arrangements; arranges for the delivery of that gas by securing interstate and intrastate capacity rights; and acquires gas storage.[101]

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[100] The commodity cost of the natural gas is recovered in a different proceeding.

[101] The Gas Acquisition Department is also responsible for procuring and trading emission allowances for the SoCalGas facilities. However, the costs associated with this responsibility will occur in a different proceeding.

ORA reviewed SoCalGas' request for its O&M gas procurement costs, and does not oppose the amount that SoCalGas is requesting. None of the other parties have objected to SoCalGas' gas procurement costs.

Based on the testimony of SoCalGas and ORA, the agreed upon settlement amount of $3.993 million for SoCalGas' O&M gas procurement cost is reasonable, and should be adopted.

7.7. Customer Services

As shown at line 10 of SoCalGas' summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion, the settling parties have agreed to $338.423 million for O&M costs for SoCalGas' customer services. In its update testimony, SoCalGas requested $356.620 million.[102] (See SoCalGas Update Testimony, Table KN-8.)

The O&M costs for SoCalGas' customer services is derived from the O&M costs found in: Exhibit 89 (customer services field and meter reading); Exhibit 110 (customer service office operations); Exhibit 115 (customer service – information; and Exhibit 185 (customer service technologies, policies and solutions). (See Exhibit 218, Table KN-8; SoCalGas Update Testimony, Table KN-8.)

The customer services category of O&M costs cover various field, office, and information activities as described in the exhibits listed above. For the customer services field and meter reading, this includes functions and activities to complete customer and company-generated work orders, such as: establishing and terminating utility service; lighting gas pilots and conducting

[102] SoCalGas originally requested a total of $356.208 million for customer services O&M costs.

customer appliance checks; shutting off and restoring gas service for fumigation; investigating reports of gas leaks and responding to other emergencies; investigating the cause of high bills; performing meter and regulator changes and other related services at customer premises; and meter reading.

For customer service office operations, these functions and activities include the following: customer contact centers; branch offices; billing and payments; credit and collections; and other related supporting functions.

The functions and activities for customer service information include the following: account management services to nonresidential and residential customers, as well as residential developers; capacity, pipeline, and storage services; gas scheduling; gas transmission planning; customer research; and outreach, communication, and education activities.

For customer service technologies, policies and solutions, these functions and activities include the following: development and implementation of policies and regulations and technologies to promote and optimize the use of natural gas as an environmentally beneficial and cost effective energy solution; enhance the safety and reliability of the natural gas delivery system; support customer adoption and use of low emission technologies; and support company-wide initiatives in related areas.

In ORA's updated testimony, ORA recommended customer services' O&M costs of $319.330 million instead of SoCalGas' updated O&M request of $356.620 million. ORA's recommendation for the lower O&M costs, as described in Exhibit 353, is due to the use of different methodologies than what SoCalGas used, and ORA's belief that SoCalGas did not fully justify some of its forecasts of costs.

Based on the testimony of SoCalGas, ORA, and the Attachment 1 settlement agreement to the SoCalGas Settlement Motion, the agreed upon amount of $338.423 million for the O&M costs for customer services is reasonable and should be adopted as it reflects a compromise of the O&M forecasts that SoCalGas and ORA had recommended.[103]

For the capital expenditures related to the customer services for SoCalGas, the need for those costs are described in Exhibits 89, 110, and 115. However, the funding requests for those capital expenditures are included in the IT capital costs, which are discussed below.

7.8. Information Technology (IT)

7.8.1. O&M Costs

Line 12 of SoCalGas' summary of earnings table, which appears in Attachment 1 of the SoCalGas Settlement Motion, shows the agreed upon settlement amount of $22.155 million for the IT O&M costs. This is derived from the agreements reached for IT O&M costs at page 8 of the SoCalGas Settlement Comparison Exhibit.

In its testimony, SoCalGas had requested $23.624 million. A breakdown of the cost components which make up the IT O&M costs for SoCalGas is shown in Exhibit 148, Table KN-9 of Exhibit 218, and Table KN-9 of the Update Testimony.

The IT O&M costs provide technology support services. These IT resources include support for the following kinds of activities: asset management; work management and measurement; fuel and power; outage management; gas and electric facilities; transportation; procurement and

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[103] See SoCalGas Settlement Comparison Exhibit at 7.

settlement; financial management; accounting; customer field operations; meter reading; customer energy management; smart meter data management; service order routing; scheduling and dispatching work orders to field personnel; revenue cycle processing; and customer assistance and customer contact functions.

As shown at line 12 of the summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion, and in Exhibit 385, ORA recommended IT O&M costs of $20.440 million.[104] As more fully described in Exhibit 385, ORA's recommended O&M costs are lower than SoCalGas due primarily to ORA's use of the 2013 recorded amount to use as the base year for the forecasting of the labor costs.

Based on the testimony of SoCalGas and ORA, and comparing their recommendations to the amounts agreed to in Attachment 1 of the SoCalGas Settlement Motion, the agreed upon IT O&M costs of $22.155 million is reasonable, and should be adopted.

7.8.2. Capital Expenditures

At pages 11 and 12 of the SoCalGas Settlement Comparison Exhibit, the settling parties have agreed to the following capital expenditures for IT: 2014 - $79.709 million; 2015 - $119.916 million; 2016 - $104.796 million.

In Exhibit 148, SoCalGas had recommended the following capital expenditures: 2014 – $103.739 million; 2015 - $119.916 million; 2016 - $104.796 million. These capital expenditure projects are sponsored by

[104] Due to rounding differences, Exhibit 385 shows the amount of $20.438 million.

various business units within SoCalGas, and by the IT division. (See Exhibit 148 at 19-20.)

ORA recommends the following capital expenditures: 2014 - $79.709 million; 2015 - $99.824 million; and 2016 - $104.796 million. ORA's recommendation for the 2014 capital expenditures is based on the actual recorded expenditures for 2014 of $79.709 million. ORA's 2015 forecast of capital expenditures is lower because the historical spending for IT has been below what SoCalGas requests for 2015, and because the majority of projects were still in the early planning stages. ORA did not oppose SoCalGas' forecast of capital expenditures for 2016.

Based on the testimony of SoCalGas and ORA concerning the IT capital expenditures, and comparing their positions to the agreed upon amounts in Attachment 1 of the SoCalGas Settlement Motion, the following agreed upon amounts for the IT capital expenditures are reasonable, and should be adopted: 2014 - $79.709 million; 2015 - $119.916 million; and 2016 - $104.796 million.

7.9. Support Services

7.9.1. O&M Costs

Line 13 of SoCalGas' summary of earnings table, which appears in Attachment 1 of the SoCalGas Settlement Motion, shows the O&M costs for the support services. A breakdown of all of the cost elements which make up the O&M costs for support services is shown in SoCalGas' Update Testimony in Table KN-10, and in Table KN10 of Exhibit 218. The cost elements which make up the support services for SoCalGas' operations are composed of the following pieces of testimony: Exhibit 177 – environmental services; Exhibit 127 – supply management; Exhibit 162 – fleet services and facility operations; and Exhibit 267 – real estate.

The settling parties have agreed to a total amount of $134.335 million for the O&M costs for support services. At pages 8-9 of the SoCalGas Settlement Comparison Exhibit, the settling parties agree that this settlement amount is to be made up of the following: $11.928 million for environmental services; $20.242 million for supply management; $84.555 million for fleet services; and $17.611 million for real estate, land services and facilities.

In its update testimony, SoCalGas requested total combined O&M costs for support services of $140.190 million.[105] This total amount is made up of the following: $12.332 million for environmental services; $21.223 million for supply management; $88.022 million for fleet services and facility operations; and $18.613 million for real estate.

In Exhibit 383, ORA recommended total combined O&M costs for support services of $125.607 million. This total of $125.607 million is made up of the following: $11.535 million for environmental services; $19.138 million for supply management; $78.034 million for fleet services and facility operations; and $16.900 million for real estate, land services and facilities. As described in Exhibit 383, ORA's recommendations are generally lower than SoCalGas' recommendations because of the different methodologies that ORA used, and ORA's disagreement with some of the incremental funding requested by SoCalGas.

In comparing the testimony of SoCalGas to ORA's testimony, and reviewing the agreement reached in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, the agreed upon amounts for the O&M costs

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105 As shown in Table KN-10 of Exhibit 218, SoCalGas originally requested $140.190 million.

for the support services category are reasonable, and the following settlement amounts should be adopted: $11.928 million for environmental services; $20.242 million for supply management; $84.555 million for fleet services; and $17.611 million for real estate, land services and facilities. These agreed upon amounts add up to total O&M costs of $134.335 million for support services.

7.9.2. Capital Expenditures

The only capital expenditures being requested for support services are for fleet services and facility operations as shown in Exhibits 162 and 383. In Exhibit 162, SoCalGas requests the following capital expenditures that are to be performed by the fleet services and facility operations unit:
2014 - $31.097 million; 2015 - $36.050 million; and 2016 - $38.011 million.

The fleet services and facility operations unit is responsible for the management, acquisition, maintenance, repair, and salvaging of vehicles and related equipment. These vehicles and equipment include automobiles, light, medium and heavy duty trucks, and power operated equipment such including trailers and forklifts.

ORA recommended that the following capital expenditures be adopted for the fleet services and facility operations: 2014 - $27.628 million; 2015 - $33 million; and 2016 - $33 million. ORA's recommendation for 2014 reflects the 2014 actual recorded expenditures. ORA's recommendations for the 2015 and 2016 capital expenditures are lower because it used a five year average instead of SoCalGas' four year average.

In the SoCalGas Settlement Comparison Exhibit at 11, the settling parties have agreed to the following capital expenditures for fleet services and facility operations: 2014 - $27.628 million; 2015 - $36.050 million; and
2016 - $38.011 million.

Based on a review of the testimony of SoCalGas and ORA concerning the capital expenditures for the support services category, and comparing that to what the settling parties have agreed to in Attachment 1 of the SoCalGas Settlement Motion, the following agreed upon capital expenditures are reasonable and should be adopted: 2014 - $27.628 million; 2015 - $36.050 million; and 2016 - $38.011 million.

7.9.3. Attachment 3 Settlement Agreement

As described in Section 6.10.3 of this decision, EDF and the Applicants entered into the Attachment 3 Settlement Agreement to the SoCalGas Settlement Motion.

For the reasons discussed in Section 6.10.3, the Attachment 3 Settlement Agreement to the SoCalGas Settlement Motion is reasonable and should be adopted.

7.9.4. Attachment 4 Settlement Agreement

In Section 6.10.4. of this decision, we discussed the Attachment 4 Settlement Agreement to the SDG&E Settlement Motion.

Since the Attachment 4 Settlement Agreement is identical for SDG&E and SoCalGas, the Attachment 4 Settlement Agreement to the SoCalGas Settlement Motion is reasonable, and should be adopted, for the same reasons that were discussed earlier for SDG&E.

7.10. Administrative and General

7.10.1. AG Costs

Line 14 of SoCalGas' summary of earnings table, which appears in Attachment 1 of the SoCalGas Settlement Motion, shows the A&G costs. The settling parties have agreed to a total amount of $377.270 million. This agreed upon settlement amount is made up of the amounts agreed to at pages 9-10 of the SoCalGas Settlement Comparison Exhibit that is attached to the SoCalGas Settlement Motion, and as shown by the workgroup categories that appear at page 287 of that same document. The derivation of the updated and original A&G costs that SoCalGas requested is shown in Table KN-11 of Exhibit 218 and SoCalGas' Update Testimony.

The cost elements which make up the A&G costs are described in the following pieces of SoCalGas' testimony: Exhibit 283 – regulatory affairs/accounting and finance/legal/external affairs; Exhibit 191 – compensation, health, and welfare; Exhibit 106 – Office of SoCalGas President and CEO, COO and VP of human resources, human resources department, and workers' compensation and long term disability (A&G – human resources); Exhibit 277 – pension and postretirement benefits other than pension; Exhibit 220 – corporate center-general administration; Exhibit 208 – corporate center-insurance; and Exhibit 13 – risk management and policy.

In its update testimony, SoCalGas requested A&G costs of $433.618 million. This total amount is made up of the following: $29.065 million for regulatory affairs, accounting and finance, legal, and external affairs; $188.209 million for compensation, health, and welfare; $52.394 million for A&G-human resources; $83.610 million for pension and postretirement benefits other than pension; $51.300 million for corporate center-general administration; $18.753 million for corporate center-insurance; $2.592 million for risk management and policy; and $7.695 million for shared asset expense.

ORA recommended total A&G costs of $356.930 million. This total of $356.930 million is composed of the following: $29.079 million for regulatory affairs, accounting and finance, legal, and external affairs (Exhibit 391); $138.200 million for compensation, health, and welfare (Exhibit 333); $45.108

million for A&G-human resources (Exhibit 389); $83.610 million for pension and postretirement benefits other than pension (Exhibit 333); $47.267 million for corporate center-general administration (Exhibit 387); $18.752 million for corporate center-insurance (Exhibit 387); and $2.592 million for risk management and policy (Exhibit 381). As described in those exhibits, ORA's recommendations are generally lower than SoCalGas' recommendations because of the different methodologies that ORA used, and ORA's disagreement with some of the incremental funding and staffing requested by SoCalGas.

In reviewing the testimony of SoCalGas and ORA, and comparing it to the agreements reached in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, the agreed upon settlement amounts for the A&G costs are reasonable, and the total A&G settlement amount of $377.270 million, which is derived as shown at page 287 of the SoCalGas Settlement Comparison Exhibit, as adjusted by the bonus depreciation adjustment resulting in the amount of $377.267 million, should be adopted.

7.10.2. Attachment 2 Settlement Agreement

As described in Section 6.11.2. of this decision, FEA and the Applicants entered into the Attachment 2 Settlement Agreement to the SoCalGas Settlement Motion.

For the reasons discussed in Section 6.11.2., the Attachment 2 Settlement Agreement to the SoCalGas Settlement Motion is reasonable and should be adopted.

7.10.3. Incentive Compensation Plan

See Section 6.11.3. for the applicability of the incentive compensation plan discussion to SoCalGas.

7.11. Other Adjustments to Operations and Maintenance Expenses

As shown at lines 15 through 19 of SoCalGas' summary of earnings table, the following five categories need to be taken into account in calculating the total operations and maintenance expenses: shared services adjustments; reassignments; escalation; uncollectibles; and franchise fees.

7.11.1. Shared Services Adjustments

Line 15 of SoCalGas' summary of earnings table shows the adjustment for shared services. This adjustment is for shared service activities that are performed by SoCalGas for the benefit of: (1) SDG&E or SoCalGas; (2) Sempra Energy corporate center; and/or (3) any unregulated subsidiaries. According to SoCalGas, the shared service cost that is incurred by one utility on behalf of another, are allocated and billed to those companies receiving that service.

In its update testimony, SoCalGas calculated shared services adjustments of $59.829 million.[106] This calculation is based on the shared services costs that the other SoCalGas witnesses derived.

ORA's testimony in Exhibit 387 states that it does not oppose the Applicants' shared services billing process and allocation of shared services costs. However, ORA has calculated total shared services adjustments of $59.709 million based on the different costs that the various ORA witnesses derived.

The settling parties have agreed to total shared services adjustments of $59.188 million. This agreed upon amount of $59.188 million is derived from the other agreed upon settlement costs that contained shared services costs. Based

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[106] SoCalGas originally requested $59.853 million for the shared services adjustment.

on our acceptance of the other agreed upon settlement amounts, as discussed above, the shared services adjustments of $59.188 million is reasonable and should be adopted.

7.11.2. Reassignments

Line 16 of SoCalGas' summary of earnings table shows the reassignments of cost. These reassignments are performed to recognize that some of the costs (A&G, labor overhead, and non-labor clearing overhead costs) are incurred to support SoCalGas' capital-related construction efforts. The costs that are reassigned to capital become part of SoCalGas' rate base.

In Exhibit 307, SoCalGas originally proposed that the total amount of $82.305 million be reassigned to capital. In its updated testimony, SoCalGas proposed that $98.668 million be reassigned.

ORA recommended in Exhibit 367 that $82.035 million be reassigned. ORA's testimony states that it does not oppose SoCalGas' reassignments, but ORA's recommended amount is based on the different costs that the various ORA witnesses derived.

The settling parties have agreed to the total reassignments amount of $87.994 million. This agreed upon amount of $87.994 million is derived from the other agreed upon settlement costs that addressed the reassignment of O&M costs to capital costs. Based on our acceptance of the other agreed upon settlement amounts, as discussed above, the reassignments amount of $87.994 million is reasonable and should be adopted.

7.11.3. Escalation

Line 17 of SoCalGas' summary of earnings table shows the costs for the escalation adjustment. This escalation adjustment is to account for the effects of inflation on SoCalGas' forecasted costs that are in 2013 nominal dollars, and to adjust them to TY 2016 nominal dollars. This escalation discussion is different from the discussion of the cost escalators for post-TY 2016, which is discussed later in this decision.

Originally, SoCalGas' escalation adjustment used the cost escalator from Global Insight's 4th Quarter 2013 Power Planner Forecast that was released in February 2014, and which proposed an escalation amount of $65.357 million. According to SoCalGas, these escalators are based on recorded utility cost data that the FERC has gathered, which are then converted into forecasts by Global Insight. The forecasts that SoCalGas used are discussed in more detail in Exhibit 303.

In its update testimony, SoCalGas updated its cost escalation using the indexes from 1st Quarter 2015 Power Planner Forecast of Global Insight. This update testimony results in an escalation adjustment of $58.088 million.

When ORA reviewed SoCalGas' application, ORA relied on Global Insight's 4th Quarter 2014 Power Planner Forecast to derive its escalation amount of $51.549 million.

In the SoCalGas Settlement Comparison Exhibit at 10, the settling parties stipulate to the use of ORA's escalation forecasts from the RO model. The use of ORA's escalation forecasts results in an escalation amount of $54.133 million as shown at line 17 of SoCalGas' summary of earnings table in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion.

Based on a review of the testimony of SoCalGas and ORA, and the agreement to use ORA's escalation forecasts in the RO model, the use of ORA's escalation forecasts is reasonable because it results in an amount that reflects the more up to date forecast that SoCalGas used in its update testimony.

Accordingly, ORA's escalation factors should be adopted to derive the escalation amount.

7.11.4. Uncollectibles

Line 18 of SoCalGas' summary of earnings table in Attachment 1 of the SoCalGas Settlement Motion addresses the amount associated with uncollectibles. The uncollectibles amount reflects an adjustment to the revenue requirement for unpaid customer bills.

In Exhibit 110, SoCalGas proposes that the uncollectible expense rate be increased from 0.278% to 0.312%. SoCalGas is requesting an increase in the "uncollectible rate to reflect collection practices adopted in recent years while also incorporating cyclical economic factors, unpredictable and random weather conditions, and natural gas price conditions." (Ex. 110 at 78.)

ORA recommends in Exhibit 353 that the uncollectibles rate be set at 0.298%. ORA "used a three year average because it shows the fluctuations in the recorded uncollectible expenses associated with the most current economic and cyclical variables." (Ex. 353 at 82.)

At page 12 of the SoCalGas Settlement Comparison Exhibit, the settling parties agree to ORA's forecasted uncollectibles rate of 0.298%. This rate results in the uncollectibles amount of $6.195 million, as shown at line 18 of SoCalGas' summary of earnings table.[107]

Based on the testimony of SoCalGas and ORA, it is reasonable to use ORA's uncollectibles rate of 0.298% as it reflects the fluctuations in the recorded

[107] Under the "Description" column for line 18 of SoCalGas' summary of earnings table, the percentage listed for uncollectibles is 0.312%. This percentage amount probably differs from the uncollectibles factor of 0.298% that is set forth in the SoCalGas Settlement Comparison Exhibit at 12 because of rounding error.

uncollectibles expense. The use of ORA's uncollectibles rate, as applied to the agreed upon revenue requirement, and as adjusted by the bonus depreciation adjustment, results in an uncollectibles amount of $6.138 million. ORA's uncollectibles percentage of 0.298% should be adopted.

7.11.5. Franchise Fees

Line 19 of SoCalGas' summary of earnings table sets forth the amount for franchise fees. As described in Exhibit 244 at 18, the "Franchise fees are payments made to counties and incorporated cities pursuant to local ordinances granting a franchise to the company to place utility property in the public rights of way." These franchise fee payments are based on the gross receipts of the utility, and for SoCalGas, are calculated using the "Broughton Act" formula, and the "Percent of Gross Receipts" formula. As of January 1, 2013, SoCalGas had franchise fee agreements with 245 taxing jurisdictions.

SoCalGas' franchise fee amount shown in its summary of earnings table in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, uses a franchise fee factor of 1.4136%. Using this factor, SoCalGas' updated testimony resulted in a franchise fee amount of $31.905 million.[108]

In ORA's testimony in Exhibit 394, ORA agrees with SoCalGas' use of the franchise fee factor of 1.4136%. The application of that factor to ORA's calculation of the TY 2016 revenue requirement resulted in a franchise fee amount of $29.317 million.

Line 19 in the SoCalGas summary of earnings table in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion shows the settlement

[108] In Exhibit 244, the application of the 1.4136% factor resulted in SoCalGas' original request of $32.053 million.

amount of $30.352 million for franchise fees. In the description column for line 19 of that table, the percentage of 1.4136% is shown for the franchise fees.

Since the settling parties have agreed to a TY 2016 revenue requirement of $2.219 billion, it is reasonable to use the franchise fee factor embedded in the settlement agreement's RO model, as adjusted by the bonus depreciation adjustment, which yields a franchise fees amount of $30.075 million, and that embedded franchise fee factor should be adopted.

7.12. Other Components of the Revenue Requirement

As part of the formula for developing the revenue requirement, the additional capital-related costs of depreciation and amortization, taxes on income, and taxes other than on income, need to be accounted for. These three cost elements are added to the total O&M costs, which results in the total operating expenses. As shown in SoCalGas summary of earnings table at lines 24 to 33, adding together the "total operating expenses" and the "return" on ratebase produces the overall revenue requirement.

The settling parties do not mention their agreement on the amounts agreed upon for depreciation and amortization, taxes on income, and taxes other than on income. Instead, these amounts are shown in the summary of earnings table in the SoCalGas settlement agreement of the SoCalGas Settlement Motion. In addition, those same amounts are listed at page 288 of the SoCalGas Settlement Comparison Exhibit.

7.12.1. Depreciation

As shown in SoCalGas' summary of earnings, the settling parties have agreed to a depreciation amount of $403.836 million.

In its updated testimony, SoCalGas requested $409.557 million for depreciation.[109] The derivation of SoCalGas' depreciation and amortization, and its accumulated reserve, is shown in Exhibit 300. According to SoCalGas, the "purpose of depreciation and amortization expense is to provide for recovery of the original cost of plant (less estimated net salvage) over the used and useful life of the property by means of an equitable plan of charges to operating expenses." (Exhibit 300 at iii.)

ORA reviewed SoCalGas' derivation of the depreciation and amortization expense, and depreciation reserve, in Exhibit 393. ORA did not recommend any changes to SoCalGas' depreciation parameters. ORA's summary of earnings recommended $401.670 million in depreciation and amortization expense. This amount of $401.670 million differs from SoCalGas' original amount of $409.501 million because of the "difference in their respective capital expenditures forecasts for 2014-2016." (Exhibit 366 at 25.)

The agreed upon settlement amount of $403.836 million for depreciation and amortization is reasonable, and should be adopted, as it reflects the changes made to the various capital expenditure forecasts that were agreed to by the settling parties.

7.12.2. Income Taxes

The income tax expense for SoCalGas is discussed with SDG&E's income tax expense in Section 6.13.2. of this decision.

[109] In Exhibit 300 at page 1, SoCalGas originally requested a total of $409.501 million for the 2016 depreciation and amortization.

7.12.3. Taxes Other Than on Income

These taxes for SoCalGas are composed of payroll taxes, and ad valorem taxes. In its update testimony, SoCalGas forecasts that payroll and ad valorem taxes will amount to $99.544 million. In Exhibit 244, SoCalGas originally forecasted a total amount of $99.671 million, which is composed of $48.244 million for payroll taxes, and ad valorem taxes of $51.427 million. The payroll taxes are composed of the following three elements: (1) FICA; (2) Federal Unemployment Tax Act; and (3) the CSUI. The ad valorem taxes are based on the assessed value of the property and the tax rate that is applied.

ORA recommends a total amount of $92.562 million for payroll taxes and ad valorem taxes. In Exhibit 394, ORA recommends that SoCalGas' calculation of payroll taxes use updated wage bases under FICA, and the 2015 tax rate under the CSUI. For ad valorem taxes, ORA agrees with SoCalGas' forecast for property taxes and SoCalGas' proposed tax rate. The differences between the ad valorem forecasts of SoCalGas and ORA are due to the differences in their respective TY 2016 estimate of plant additions.

In the summary of earnings table of the Attachment 1 settlement agreement to the SoCalGas Settlement Motion, the amount of $95.433 million is shown for taxes other than income. In the SoCalGas Settlement Comparison Exhibit at page 12 under the heading of "Other Issues," the settling parties agree to ORA's forecasted payroll tax rate of 7.58%.

Based on a comparison of how SoCalGas and ORA developed their forecasts of payroll taxes and property taxes, and the methodology agreed to in the SoCalGas Settlement Agreement, it is reasonable to adopt the methodology that the settling parties agreed to for taxes other than income, as adjusted by the bonus depreciation adjustment, and which generated the amount of $94.948 million.

7.13. Rate Base and Return on Rate Base

The last three components of calculating the revenue requirement are rate base, the rate of return, and the return on rate base. The amount of the rate base is multiplied by the authorized rate of return to produce the return on rate base. This return on rate base is added to the other components, which when added together, totals to the revenue requirement.

SoCalGas defines rate base "as the net investment of property, plant, equipment and other assets that [SoCalGas] has acquired or constructed to provide utility services to its customers." (Exhibit 298 at 2.) As noted earlier, ORA defines rate base as "the depreciated asset value of the utility's net investments used to provide service to its customers." (Exhibit 396 at 1.) As described in Exhibit 298, the four major components of rate base are fixed capital, working capital, other deductions, and deductions for reserves.

At line 26 of SoCalGas' summary of earnings table in the SoCalGas settlement agreement of the SoCalGas Settlement Motion, the agreed upon amount of $4,137,633,000 is shown for rate base. This rate base amount of approximately $4.138 billion is derived from the capital-related costs that the settling parties have agreed upon.

In SoCalGas' update testimony, SoCalGas requested a rate base amount of $4,233,180,000 in its update testimony. In SoCalGas' rate base testimony in Exhibit 298, SoCalGas originally requested a rate base amount of $4,265,837,000. SoCalGas' derivation of the rate base is explained in Exhibit 298, which is based on the testimony of other witnesses regarding capital expenditures.

In Exhibit 396 at 5, ORA recommended a rate base amount of $4,080,303,000 for SoCalGas.[110] ORA's derivation of the rate base amount is based on the testimony of other ORA witnesses as noted in Exhibit 396 at 4.

In Exhibit 396, ORA also recommended a working cash amount for SoCalGas of a negative $2.135 million, which is lower than the working cash amount of $79.900 million that SoCalGas had requested. ORA's recommendation for a lower working cash amount is because of the following reasons, as more fully explained in Exhibit 396: (1) SoCalGas' cash balances should be excluded from the working cash calculations; (2) ORA's use of 41.55 as the revenue lag days for the working cash calculations, instead of SoCalGas' use of 42 days; (3) ORA's use of 37.50 for the federal income tax lag days, instead of SoCalGas' use of a negative 724.93 days; (4) ORA's use of 20.60 for the CCFT lag days, instead of SoCalGas' use of a negative 573.92 days; and (5) ORA's recommendation that customer deposits should be treated as a source of debt, which should result in a $3.072 million reduction to SoCalGas' revenue requirement.

In addition to the $4.138 billion for rate base that the settling parties have agreed to as part of the Attachment 1 settlement agreement of the SoCalGas Settlement Motion, the settling parties also agreed to certain working cash related issues as shown in the SoCalGas Settlement Comparison Exhibit at 12, and as mentioned in the paragraph above. The working cash, along with the costs of materials and supplies, make up the working capital component of the rate base.

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110 In its Summary of Recommendations in Exhibit 396 at 4, ORA appears to have mistyped the rate base amount as $4.808 billion instead of $4.080 billion.

Comparing the positions of SoCalGas and ORA on the amount of rate base that should be included in the calculation of the return on rate base, the capital-related costs that the settling parties have agreed to, and the adjustment that we adopt for the repairs deduction, it is reasonable to adopt the amount of $3,974,851,000 as the rate base amount.

To derive the return on rate base, the rate of return of 8.02% is used. That percentage reflects what the Commission approved in the 2013 TY cost of capital proceeding approved in D.12-12-034. ORA agrees with the use of the 8.02% for the rate of return.

Since there is no disagreement regarding the use of the 8.02% rate of return, and because that percentage factor was the amount that was authorized in the last cost of capital proceeding, it is reasonable to adopt the 8.02% rate of return in the calculation of the return on rate base.

Using the agreed-upon rate base amount of $4,137,633,000 and the rate of return of 8.02%, that results in the TY 2016 return on rate base amount of $318.783 million.

7.14. Miscellaneous Revenues

As noted earlier, the miscellaneous revenues reduce the base margin revenue requirement that SoCalGas customers pay.

Miscellaneous revenues appear at lines 2 and 34 of SoCalGas' summary of earnings table in the Attachment 1 settlement agreement of the SoCalGas settlement motion. According to SoCalGas, "Miscellaneous revenues are comprised of fees and revenues collected by the utility from non-rate sources for the provision of specific products or services." (Exhibit 228 at 1.) As described in Exhibit 228, these miscellaneous revenues include service establishment charges, pipeline services, and other gas-related services.

In its updated testimony, SoCalGas proposed miscellaneous revenues of $100.561 million. Originally, in SoCalGas' Exhibit 228, it proposed miscellaneous revenues of $100.513 million.

In ORA's update testimony in Exhibit 366, and in ORA's testimony on miscellaneous revenues in Exhibit 371, ORA recommended $102.118 million in miscellaneous revenues.[111] As described in Exhibit 371, ORA took issue with SoCalGas' forecast of the service establishment charge revenues.

As described in SoCalGas' rebuttal testimony in Exhibit 230, SoCalGas disagrees with ORA's methodology because it is based on a five year average for some revenues, but not for others. SoCalGas also contends that ORA's use of a five year average methodology is inconsistent with how ORA calculated the TY 2016 cost estimate for customer service field costs. Had ORA used a five year average for estimating the customer service field order volumes, SoCalGas contends that would have resulted in a higher cost estimate for customer service field costs.

In the SoCalGas Settlement Comparison Exhibit at 283, the settlement amount of $99.280 million appears in line 2 of the summary of earnings table. At pages 12 and 13 of the SoCalGas Settlement Comparison Exhibit, the settling parties specifically agree to ORA's miscellaneous revenues forecast for the following: service establishment charges of $25.467 million; reconnect charges of $1.537 million; residential limited parts program of $2.057 million; and third party revenues of $1.159 million.

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[111] In ORA's summary of earnings table for SoCalGas in Exhibit 367, the amount of $98.332 million is shown for miscellaneous revenues. This amount of $98.332 million also appears as the number recommended by ORA in the SoCalGas Settlement Comparison Exhibit at 283.

We have reviewed the original positions of SoCalGas and ORA, and also compared their positions to the amounts agreed to in the Attachment 1 settlement agreement of the SoCalGas Settlement Motion. Based on their original positions, the amounts agreed upon in the Attachment 1 settlement agreement, and the adjustments we made, it is reasonable to adopt the amount of $98.685 million for SoCalGas' miscellaneous revenues.

7.15. PTY Ratemaking

7.15.1. Attrition Year Adjustment

Our discussion of the PTY ratemaking mechanism is very similar to our discussion of the SDG&E PTY ratemaking mechanism.

Prior to the filing of the PTY Settlement Motion, SoCalGas proposed a three-year GRC term of 2016-2018, with its next GRC cycle beginning with TY 2019. SoCalGas' reasoning for the three year GRC term was to avoid conflicts with the expected GRC filings of PG&E and SCE.

For this two year attrition period of 2017 and 2018, SoCalGas proposes a PTY ratemaking mechanism that is comprised of two components: O&M escalation, and capital-related costs. Using SoCalGas' proposed PTY ratemaking mechanism, SoCalGas estimates an attrition year revenue requirement increase of $125 million (5.3%) in 2017, and an increase of an additional $94 million (3.8%) in 2018.

The O&M escalation would make adjustments for labor and non-labor costs, and for medical costs. For the labor and non-labor costs, SoCalGas proposes to use the Global Insight forecasts as described by SoCalGas' escalation witness in Exhibit 303. According to Exhibit 92, the dollar escalation increase for attrition year 2017 would be effective January 1, 2017, and would be based on the Global Insight forecast available in September 2016. For the dollar escalation increase for the attrition year beginning January 1, 2018, the escalation index would be based on the September 2017 Global Insight forecast.

For the medical care adjustments to the O&M escalation, SoCalGas proposes that the medical costs be increased by 7.8% in both 2017 and 2018. SoCalGas' medical care adjustment is based on the actuarial forecast of Towers Watson as described in Exhibit 191.

The second component of SoCalGas' PTY ratemaking mechanism is the adjustment for capital additions. This adjustment is to the capital-related revenue requirements to reflect the cost of plant additions. During the PTY period, SoCalGas is proposing to adjust the rate base and the associated revenue requirements to reflect the impact of forecasted capital additions. SoCalGas' capital additions adjustment uses a seven-year average of historical and forecasted capital additions as a proxy for future capital additions. To derive this seven-year average, the capital additions during this period are first escalated to 2016 dollars and then averaged. SoCalGas points out that its capital additions adjustment is consistent with the approach that the Commission approved for PG&E in D.14-08-032.

To implement the PTY ratemaking mechanism, SoCalGas proposes to continue the process of making these adjustments through an annual PTY advice letter filing that takes place on or before November 1. The resulting rate adjustment for the attrition year would be effective on January 1 following the filing of the advice letter.

ORA recommends in Exhibit 398 that an additional attrition year be added to the Applicants' three year GRC term. Instead of attrition years 2017 and 2018, ORA requests that the attrition years cover 2017, 2018 and 2019. ORA contends that a four year "GRC cycle allows for better utility financial and operational management of spending and investment." (Ex. 398 at 13.)

ORA is agreeable to a PTY ratemaking mechanism that provides the Applicants with some reasonable level of revenue increases for the attrition years. As discussed earlier in the SDG&E PTY ratemaking mechanism section, ORA recommends that the PTY ratemaking mechanism use a 3.5% increase factor for each of the attrition years.

In the SoCalGas Settlement Agreement, the settling parties have agreed to ORA's PTY ratemaking recommendation of a 3.5% increase in 2017, and a 3.5% in 2018. (SoCalGas Settlement Motion, SoCalGas Settlement Comparison Exhibit at 12.)

The PTY Settlement Motion that the Applicants and ORA filed applies to SoCalGas as well. As noted earlier in the SDG&E PTY ratemaking mechanism discussion, the PTY Settlement Agreement provides for a 2019 attrition year, and an escalation rate of 4.3% for the 2019 attrition year.

As mentioned earlier, the petition for modification of D.14-12-025 is being addressed in a separate decision in R.13-11-006, and the proposed decision addressing this petition for modification is being considered at the June 9, 2016 Commission meeting. The proposed decision in R.13-11-006 recommends that the petition for modification of D.14-12-025 be denied.

As discussed earlier, and consistent with the outcome expected in R.13-11-006, this decision denies the PTY Settlement Motion to adopt the PTY Settlement Agreement.

As a result, the GRC cycle for SDG&E and SoCalGas shall remain a three year rate cycle, and for purposes of these consolidated proceedings, the GRC cycle shall consist of TY 2016 and the attrition years of 2017 and 2018.

Having resolved the issue about the length of the GRC cycle, the next issue is to decide whether the 3.5% PTY ratemaking mechanism agreed to in the SoCalGas Settlement Agreement is reasonable. As mentioned above, we have reviewed the testimony of ORA and SoCalGas, and compared their recommendations to the agreed upon PTY ratemaking mechanism. We have also considered the pleadings filed in connection with the PTY Settlement Motion. Based on all those considerations, the agreed upon 3.5% PTY ratemaking mechanism is reasonable and should be adopted for each of the attrition years.

7.15.2. SoCalGas Advanced Metering Infrastructure

The advanced metering infrastructure (AMI) refers to SoCalGas' deployment of smart meters in its service territory. The Commission approved SoCalGas' deployment of AMI in D.10-04-027, and in Advice Letter 4110.

SoCalGas expects to complete the deployment of AMI in 2017. Since SoCalGas did not have sufficient data prior to preparing its TY 2016 GRC application, the cost forecasts for TY 2016 "reflect business operations, processes and practices without AMI deployment." (Exhibit 124 at 3.) As a result, no AMI costs or benefits were presented by SoCalGas in its TY 2016 GRC application.

Due to the continuing deployment of AMI into 2017, SoCalGas seeks authority to extend the AMI balancing account (AMIBA) through 2018, or until the costs and benefits associated with AMI can be incorporated into a subsequent GRC proceeding. According to SoCalGas' Exhibit 124, the AMIBA reconciles the differences in recorded costs and benefits, from the forecasted costs and benefits established in Advice Letter 4110, which was approved on August 4, 2010.

In the event the Commission authorizes operating expenses for TY 2016 that are materially different from those assumed in the approved AMI net revenue requirement that is currently in rates, SoCalGas proposes that it be allowed to adjust its AMI revenue requirement and operating benefits through an advice letter filing.

ORA was the only party who addressed SoCalGas' AMIBA proposal. ORA does not oppose the extension of the AMIBA. In addition, ORA does not oppose SoCalGas' request to adjust the AMI revenue requirement through an advice letter.

The SoCalGas Settlement Comparison Exhibit at 262 "does not address the merits of the parties' arguments or prejudice any party's ability to raise this issue again in an upcoming GRC."

Based on the positions of the parties, an extension of the AMIBA as requested by SoCalGas is reasonable and should be adopted. The extension of the AMIBA is reasonable because that will allow the AMI costs and benefits to be reflected in SoCalGas' TY 2019 GRC application. Since today's decision does not materially change SoCalGas' AMI revenue requirement, there is no need for SoCalGas to adjust the AMI revenue requirement.[112]

7.15.3. Z-Factor Mechanism

In Exhibit 92, SoCalGas proposes in its application to continue the current Z-factor mechanism for the GRC term. As mentioned earlier, the Z-factor mechanism is used to request rate adjustments for exogenous cost changes prior to the next GRC test year. The Z-factor mechanism allows for the rate adjustment of the portion of the Z-factor costs that are not already in SoCalGas' annual revenue requirement, and only for the costs that exceed a $5 million

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[112] D.10-04-027 authorized funding of $1.051 billion for SoCalGas' AMI system. This and all other conditions of D.10-04-027 remain unchanged.

deductible per event. In order to request a Z-factor adjustment, the reasons for the adjustment must meet the eight criteria specified in D.94-06-011.

ORA does not oppose SoCalGas' request to continue the Z-factor mechanism. However, ORA recommends that the Z-factor mechanism be effective only during the attrition years, and not for the test year.

In the SoCalGas Settlement Comparison Exhibit at 13, the settling parties have agreed to continue the Z-factor mechanism.

Based on a comparison of the positions of SoCalGas and ORA on the Z-factor, it is reasonable to continue the Z-factor mechanism without any change during the GRC cycle, and that portion of the SoCalGas Settlement Agreement should be adopted. Again, we emphasize that the Z-factor also applies to events that cause cost decreases, as well as to events that cause cost increases.

7.16. Summary of SoCalGas

Except for the settling parties agreement with respect to bonus depreciation, we conclude that the five settlements attached to the SoCalGas Settlement Motion are reasonable and in the public interest given our discussion of the original positions of the parties, in comparison to the amounts, methodologies, and other agreements set forth in the five settlements. Except as noted, the five settlements are also consistent with the law, and will provide the necessary funds to allow SoCalGas to operate its natural gas transmission and distribution systems, and its underground gas storage facilities, safely and reliably at reasonable rates. Accordingly, the SoCalGas Settlement Motion to adopt the five settlements is granted, and the five settlements attached to the SoCalGas Settlement Motion, excluding the bonus depreciation issue discussed in today's decision, should be adopted.

Due to the provision in the Attachment 5 Settlement Agreement about the tax issue involving the deduction of repairs, and the adjustments we make for bonus depreciation, today's decision adopts a TY 2016 revenue requirement of $2,199,194,000 for SoCalGas.

For the reasons stated earlier, the PTY Settlement Motion is denied.

8. Comments on Proposed Decision

The proposed decision of ALJs John S. Wong and Rafael L. Lirag in these matters was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ______________, and reply comments were filed on ______________ by ____________________.

9. Assignment of Proceeding

Michael Picker is the assigned Commissioner and John S. Wong and Rafael L. Lirag are the assigned ALJs in this proceeding.

Findings of Fact

1. TURN's motion to direct SDG&E and SoCalGas to establish memorandum accounts to track the income tax differences associated with the changes for the accounting of deductions for repairs was granted in a January 15, 2015 ruling.

2. In D.15-05-044, the Commission granted the March 13, 2015 joint motion of SDG&E and SoCalGas that they be allowed to establish GRC memorandum accounts to record the difference between the rates in effect beginning January 1, 2016, and the rates to be adopted in these proceedings in the event a final Commission decision is not rendered in time for the 2016 rates to take effect January 1, 2016.

3. 18 days of evidentiary hearings were held in June and July of 2015, and over 400 exhibits were identified and used during the course of these proceedings.

4. In response to the scoping ruling, SED prepared a report which evaluated selected safety and risk program areas that were included in the GRC applications of the Applicants.

5. Following the close of the evidentiary hearings, the Applicants began settlement discussions with several of the parties, which resulted in the September 11, 2015 filing of three separate motions to adopt settlements for SDG&E and SoCalGas.

6. A summary of the comments that were made at the PPHs and in correspondence regarding the TY 2016 requests of the Applicants are summarized in this decision.

7. The two applications cover test year (TY) 2016, with rates effective January 1, 2016, and the post-test year (PTY) periods of 2017 and 2018.

8. ORA, along with other parties, recommended that various adjustments be made to the GRC revenue requirement requests of SDG&E and SoCalGas.

9. SDG&E and SoCalGas are related companies owned by Sempra.

10. The SDG&E Settlement Motion, and the SoCalGas Settlement Motion, each contain five settlement agreements, which the settling parties request be adopted.

11. As described in this decision, Attachments 2 to 5 of the SDG&E and SoCalGas Settlement Motions are identical, but may contain provisions that are specific to both utilities or individually.

12. The Attachment 1 Settlement Agreement to the SDG&E Settlement Motion pertains only to SDG&E, and the Attachment 1 Settlement Agreement to the SoCalGas Settlement Motion pertains only to SoCalGas.

13. The summary of earnings tables, which are found in Appendix B to the SDG&E and SoCalGas Settlement Comparison Exhibits, set forth a comparison of the agreed upon revenue requirements by general cost categories to the positions of the Applicants and ORA.

14. The PTY Settlement Motion requests that the Commission adopt the settlement between the Applicants and ORA to add an additional attrition year (2019), and to escalate rates by 4.3% for that attrition year, subject to the two contingencies stated in the PTY Settlement Agreement.

15. Appendix A of this decision contains the adopted summary of earnings tables for SDG&E and SoCalGas, while Appendix B of this decision contains the adjustments that we adopt to the revenue requirements of SDG&E and SoCalGas.

16. The summary of earnings tables shown in Appendix A of this decision reflects all of the costs or methodologies we have found to be reasonable as inputs into the RO model.

17. The RO model is used by the Applicants to generate the revenue requirement amount that is needed to allow SDG&E and SoCalGas to earn the authorized rate of return on their investments.

18. As described in this decision, we have reviewed and considered all of the exhibits in this proceeding, the proposed settlements, as well as the arguments and issues that parties have raised in deciding what costs should be adopted.

19. The Commission is committed to the safety of utility operations, and the Applicants are expected to make safety a foundational priority.

20. The Commission in authorizing the adopted revenue requirements for SDG&E and SoCalGas, has placed an emphasis on programs and activities that enhance the safety and reliability of their natural gas and electric infrastructure and operations.

21. As updated in its update testimony, SDG&E requests that the Commission authorize a total revenue requirement of $1,895,437,000 ($324,188,000 for gas operations, and $1,571,249,0000 for electric operations).

22. In the combined summary of earnings table for SDG&E, the settling parties agree to a total revenue requirement of $1,810,533,000 ($310,487,000 for gas operations, and $1,500,046,000 for electric operations).

23. The cost components which make up the revenue requirement for SDG&E are reflected in SDG&E's summary of earnings tables.

24. SDG&E's electric distribution O&M costs are for activities related to the operation, maintenance, supervision, and engineering of its electric distribution system.

25. As discussed in SDG&E's electric distribution O&M section, the O&M costs of $126.760 million as set forth in the SDG&E settlement agreement are reasonable.

26. SDG&E is in a better position to determine workforce needs and can adjust the number of troubleshooters that it hires based on actual need.

27. A one-way balancing account for vegetation management costs, encourages SDG&E to perform the necessary activities related to tree trimming, and at the same time minimize costs for such activities.

28. SDG&E's electric distribution capital projects are for investments to improve capacity and reliability, and are intended to maintain the delivery of safe and reliable service to SDG&E's customers.

29. As discussed in the electric distribution capital section, and as set forth in the Attachment 1 Settlement Agreement, the amounts for: Electric Distribution Capital I of $145.552 million for 2014, $280.772 million for 2015 and $296.428 million for 2016, are reasonable; Electric Distribution Capital II of $113.902 million for 2014, $199.082 million for 2015, and $186.216 million for 2016, are reasonable.

30. Additional spending advocated for by CCUE to improve or maintain the reliability of SDG&E's electric distribution system is not supported by the evidence.

31. SDG&E's current forecast for reliability projects already allows it to maintain its high standard of reliability for its customers.

32. The establishment of a two-way balancing account for reliability improvements would diminish SDG&E's ability to prioritize or allocate expenses based on what is needed.

33. There is no need to address the battery technology issue raised by the Joint Minority Parties in this decision since they are a signatory to the SDG&E Settlement Motion.

34. SDG&E provided sufficient support to justify its spending on fire risk mitigation activities, and the forecasted amounts are based in part on historical spending for fire risk mitigation activities.

35. The agreement in the Attachment 5 Settlement Agreement for SDG&E to perform and present a study of the distributed generation impacts on circuit peak loads prior to the filing of SDG&E's next GRC application is reasonable, and will help estimate the potential of distributed generation to reduce circuit peaks and distribution expenditures in future GRCs.

36. SDG&E's gas distribution O&M costs consist of various activities to operate and maintain its pipelines and associated equipment in good working order in order to provide safe and reliable gas service to all of its customers who use natural gas.

37. As discussed in the gas distribution O&M section, the O&M costs of $23.996 million as set forth in the SDG&E settlement agreement are reasonable.

38. As discussed in SDG&E's gas distribution capital section, the amounts for: gas distribution of $32.821 million for 2014, $37.363 million for 2015 and $40.972 million for 2016, are reasonable.

39. SDG&E's gas transmission O&M costs consist of the day-to-day expenses associated with pipeline operations, gas compression operations, and field engineering and technical support services, to operate and maintain its gas transmission system.

40. As discussed in SDG&E's gas transmission section, the O&M costs of $4.663 million is reasonable.

41. As discussed in SDG&E gas transmission capital section, the following amounts for the TIMP and DIMP capital expenditures are reasonable: 2014 - $9.969 million; 2015 - $6.790 million; and 2016 - $24.215 million.

42. The capital expenditures associated with TIMP and DIMP are consistent with federal requirements to evaluate transmission and distribution pipeline systems through data gathering and inspections, and then taking action to mitigate or remediate the identified risks.

43. DREAMS represents a proactive approach to risk identification and risk management, and for prioritizing the replacement of pipe that may pose hazards.

44. SDG&E's electric generation O&M costs include the costs for the operation of its four electric generation plants.

45. As discussed in SDG&E's electric generation O&M section, the amount of $52.802 million for electric generation O&M costs is reasonable.

46. The electric generation capital expenditures include tools and equipment, and operational enhancements to SDG&E's four generation plants.

47. As discussed in SDG&E's electric generation capital section, the capital expenditures of $17.036 million for 2014, $8.408 million for 2015, and $8.347 million for 2016, are reasonable.

48. As discussed SDG&E's gas generation section, the O&M cost of $531,000 is reasonable.

49. SDG&E recovers most of the costs associated with its 20% ownership interest in SONGS based on the SONGS portion of SCE's GRC, and the few costs that are not addressed in SCE's GRC are addressed in SDG&E's GRC.

50. Despite the cessation of operations at SONGs, costs during the decommissioning phase will continue to be incurred.

51. SDG&E's Exhibit 80 stated that it may seek to recover the Unit 1 spent fuel storage costs in SDG&E's ERRA proceeding rather than through its GRC proceeding.

52. In A.15-04-014, filed on April 15, 2015, SDG&E included $1.077 million for its SONGS Unit 1 offsite spent fuel storage costs.

53. In D.15-12-032, the Commission authorized SDG&E to recover the $1.077 million for the Unit 1 offsite spent fuel storage costs.

54. The amount agreed upon in the SDG&E settlement agreement of $1.293 million for nuclear generation costs, should be reduced to $229,000 after subtracting the amount of $1.064 million for Unit 1 spent fuel storage costs.

55. Costs associated with marine mitigation are incurred for ongoing projects to mitigate the turbidity effects caused by movement of ocean water used to cool SONGS when it was operational.

56. Continuance of SDG&E's two-way balancing account for SONGS through this GRC cycle is reasonable.

57. As discussed in SDG&E's electric engineering section, the O&M costs of $0.330 million for electric engineering is reasonable.

58. SDG&E's gas engineering O&M costs consist of various activities that provide technical guidance to support the day-to-day functions for gas transmission, gas distribution, and gas storage, including TIMP and DIMP activities.

59. As discussed in SDG&E's gas engineering section, the O&M costs of $11.589 million is reasonable, which includes TIMP and DIMP costs of $11.484 million.

60. Two-way balancing account treatment to recover undercollected amounts for the TIMP and DIMP is reasonable.

61. Gas engineering capital expenditures are for projects to provide safe and reliable delivery of natural gas to customers at a reasonable cost, and include such activities as the installation of new pipelines; the replacement and relocation of pipelines; and maintaining and replacing key components of the compressor-related equipment.

62. As discussed in the gas engineering capital section, capital expenditures of $7.365 million for 2014, $6.582 million for 2015, and $7.002 million for 2016, are reasonable.

63. SDG&E's electric and fuel procurement O&M costs are the costs associated with procuring, managing, planning, and administering SDG&E's electric and fuel supply for its bundled customers.

64. As discussed in SDG&E's electric and fuel procurement section, the O&M costs of $8.647 million is reasonable.

65. As discussed in SDG&E's gas procurement section, the O&M cost of $0.110 million for gas procurement is reasonable.

66. As discussed in SDG&E's customer services section, the O&M cost of $85.448 million, and all of the sub-components of that amount as described in the SDG&E Settlement Comparison Exhibit, is reasonable.

67. The agreement in the Attachment 5 Settlement Agreement that SDG&E can file a separate application to seek the closure of any existing branch offices during SDG&E's TY 2016 GRC cycle is reasonable.

68. Funding requests for the capital expenditures associated with customer services are included in the funding requests for IT capital expenditures.

69. The IT division, which performs activities on behalf of SDG&E, SoCalGas, and Sempra, is responsible for a majority of the technology-related services such as supporting applications, hardware and software, and providing cybersecurity.

70. As discussed in the IT O&M section, the O&M costs of $106.368 million for SDG&E's electric and gas operations is reasonable.

71. As discussed in the IT capital expenditures section, the agreed upon amounts of $88.635 million for 2014, $62.084 million for 2015, and $35.388 million for 2016, are reasonable.

72. Support services for SDG&E's electric and gas operations include activities related to: environmental services; real estate, land services and facilities; fleet services; and supply management and supplier diversity.

73. As discussed in the support services section, the O&M amount of $102.961 million ($80.316 million for SDG&E's electric operations, and $22.645 million for gas operations) is reasonable.

74. As discussed in the support services capital section, the agreed upon amounts for capital expenditures of $21.017 million for 2014, $33.112 million for 2015, and $42.930 million for 2016, are reasonable.

75. The Attachment 3 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions resolves the contested issues between EDF, SDG&E, and SoCalGas.

76. The settlement terms in the Attachment 3 Settlement Agreement do not prejudge what the Commission is doing in other proceedings.

77. Adopting the NERBA as a two-way balancing account is reasonable.

78. The Attachment 4 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions resolves contested issues with the Joint Minority Parties.

79. The terms of the Attachment 4 Settlement Agreement seek to increase the visibility of the Joint Minority Parties to advocate on the behalf of underrepresented communities and small businesses, and is targeted at increasing the participation of underrepresented communities and small businesses in the various activities that the Applicants engage in.

80. The cost elements which make up SDG&E's proposed A&G costs include the following: $35.985 million for regulatory affairs, controller, finance, legal and external relations; $141.414 million for compensation, health, and welfare; $19.628 million for human resources, safety, disability, and workers' compensation; $9.550 million for pension and postretirement benefits other than pension; $64.200 million for corporate center-general administration;

$111.512 million for corporate center-insurance; $2.965 for risk management and policy; and $46.278 million for other.

81. As discussed in SDG&E's A&G section, the adjusted amount of $387.760 million for SDG&E's A&G cost is reasonable.

82. The Attachment 2 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions, in which the settling parties specifically agree that the Applicants will not include the income tax impacts into the PBA and PBOPBA, is reasonable.

83. Incentive compensation costs, which include variable pay, are included as part of A&G costs for both SDG&E and SoCalGas.

84. The stipulation in the SDG&E Settlement Comparison Exhibit to a compromise forecast of $32 million for SDG&E's variable compensation does not resolve any policy issues regarding variable compensation.

85. The stipulation in the SoCalGas Settlement Comparison Exhibit to a compromise forecast of $25 million for SoCalGas' variable compensation does not resolve any policy issues regarding variable compensation.

86. On July 20, 2015, the Energy Division staff issued data requests to SDG&E and SoCalGas for information about its "at risk" compensation, and how that compensation may be related to safety metrics.

87. The data responses of SDG&E and SoCalGas to the July 20, 2015 data requests were admitted into evidence as Exhibit 415 by the May 9, 2016 ruling of the ALJs.

88. The July 20, 2015 data requests regarding compensation raise the issue of how safety-related factors are considered in determining the award of variable compensation to non-represented employees and executives of SDG&E and SoCalGas, and the responses of SDG&E and SoCalGas in turn raise the related

issue of whether the variable compensation formula adequately promotes a safety culture, or unduly benefits shareholders with the simple metric of the companies' financial performance and earnings, and whether that creates a situation where the two interests are conflicting.

89. In MGRA's response to the September 21, 2015 ruling, it objected to a provision in SDG&E's ICP which allows the Compensation Committee of Sempra's Board to exercise its discretion in including up to 10% of the earnings impact of the wildfire litigation for ICP purposes, which MGRA contends is contrary to ratepayer interests because it rewards SDG&E's employees for seeking to have ratepayers pay for the wildfire costs even though SDG&E was at fault.

90. This decision does not prejudge or address the merits of the issues being litigated in A.15-09-010.

91. Since this GRC is examining the costs associated with compensating SDG&E's employees over the TY 2016 GRC cycle, it is appropriate to review how non-represented employees and executives at both SDG&E and SoCalGas are compensated under variable compensation.

92. One of the leading indicators of a safety culture is whether the governance of a company utilizes any compensation, benefits, or incentive to promote safety and hold employees accountable for the company's safety record.

93. To calculate the total O&M expenses for SDG&E, shared services adjustments, reassignments, FERC transmission costs, escalation, uncollectibles; and franchise fees, need to be taken into account.

94. As discussed in the shared services adjustments section, the agreed upon amount in the SDG&E Attachment 1 Settlement Agreement of $90.216 million is reasonable.

95. As discussed in the section on reassignments, the agreed upon amount in the SDG&E Attachment 1 Settlement Agreement of $114.924 million is reasonable.

96. As discussed in the section on FERC transmission costs, the amount of $55.666 million to be excluded as agreed to in the SDG&E Attachment 1 Settlement Agreement is reasonable.

97. As discussed in the section on escalation, it is reasonable to use ORA's escalation factors to derive the escalation amount.

98. As discussed in the section on Uncollectibles, it is reasonable to use the uncollectibles formula embedded in the RO model which results in an uncollectibles amount of $3.114 million.

99. As discussed in the section on franchise fees, it is reasonable to use the franchise fee factors embedded in the RO model which results in a total franchise fees amount of $57.215 million.

100. As part of the formula for developing the revenue requirement, the additional capital-related costs of depreciation, taxes on income, and taxes other than on income, need to be accounted for, and when those are added to the total O&M cost it results in the total operating expenses.

101. Adding total operating expenses and return on rate base produces the overall revenue requirement.

102. The purpose of depreciation and amortization expense is to provide for the recovery of the original cost of plant (less estimated net salvage) over the used and useful life of the property by means of an equitable plan of charges to operating expenses.

103. As discussed in the section on Depreciation, the amount of $432.059 million agreed upon in the SDG&E Attachment 1 Settlement Agreement is reasonable.

104. The two income tax issues relevant to the GRC proceedings of SDG&E and SoCalGas are the repairs deduction, and bonus depreciation.

105. These two issues arise because of the timing of when the Applicants elected to use the change in accounting method for the repairs deduction, and to claim the bonus depreciation, which in turn affect their treatment from a tax perspective and from a regulatory accounting perspective.

106. With respect to the repairs deduction, we addressed a similar adjustment for SCE, under similar circumstances, in D.15-11-021.

107. For federal tax reporting purposes, the differences between taxable income and book income are reconciled in the Schedule M attachment to the federal Corporation Income Tax Return.

108. Due to the differences in how income is reported for tax and book purposes, this also affects the depreciation used for tax and regulatory purposes.

109. The repairs deduction involves IRC §§ 162 and 263, and the characterization and tax treatment of expenditures that are related to maintenance, repair, and improvement activities.

110. During the 2011 to 2012 timeframe, when the TY 2012 GRC applications of the Applicants were pending before the Commission, the IRS issued regulations and guidance on whether repairs should be expensed or capitalized.

111. The Attachment 5 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions specifically provide that the repair issue will be litigated separately from the five settlement agreements.

112. For their TY 2016 GRC forecasts, SDG&E and SoCalGas calculated their income tax liability "using current federal and state tax laws enacted through the filing date of this testimony."

113. As a result of the Revenue Procedures referenced in this decision, SDG&E implemented a change in accounting method for the deduction of repairs to its 2011 and 2012 income tax returns, and SoCalGas implemented the change in accounting method to its 2012 income tax return.

114. The change in the accounting method allowed SDG&E and SoCalGas to begin deducting certain repairs that previously had been capitalized for book purposes.

115. SDG&E and SoCalGas do not dispute that because of the historical flow-through of income tax, that they received a benefit of around $262 million in savings from paying less income taxes due to the higher repairs deduction allowed by the change in accounting method.

116. The flow-through of the benefits to the shareholders of SDG&E and SoCalGas occurred because the tax savings were not incorporated in the Applicants' TY 2012 GRC forecasts, and the Applicants never notified the Commission or the parties in the TY 2012 GRC proceedings that they had changed or were going to change their accounting method.

117. The Applicants' witness agreed that the $262 million benefit resulting from the change in accounting method led to increased earnings for the utility.

118. TURN proposes that the federal income taxes for the years 2011-2014 be normalized beginning in TY 2016, which will increase the ADIT, and which reduces the rate base and revenue requirement of SDG&E and SoCalGas over the next 25-30 years.

119. TURN proposes that repairs memorandum account balance as of December 31, 2015 be flowed-through to ratepayers to reduce the TY 2016 rates, or as an alternative, that the 2015 amounts be normalized beginning in TY 2016.

120. We are persuaded by TURN's logic, that over the long term, ratepayers for both SDG&E and SoCalGas will end up paying higher rates than they would have had the Applicants not implemented the change to their accounting method.

121. The Applicants' change in accounting method reduced their income tax expense due to the higher amounts for repair expenses, but this change also affects the future by lowering the amount of future depreciation deductions.

122. The evidence is clear that SDG&E elected and implemented the change in the method of accounting beginning in 2012 (which first affected its 2011 income tax return), that SoCalGas elected and implemented the change beginning in 2013 (which first affected its 2012 income tax return), and that the change in accounting method was not included as part of their TY 2012 GRC filings.

123. D.13-05-010, which addressed the Applicants' TY 2012 GRC applications, was not adopted by the Commission until May 9, 2013, and there were opportunities for the Applicants to bring the change in accounting method to the attention of the Commission and the parties before then.

124. The Commission never had the opportunity to review the change in accounting method that began around September 2012, and D.13-05-010 addressed the deduction of repairs using the PRA methodology.

125. The PRA methodology is the methodology that preceded Revenue Procedure 2011-43 and Revenue Procedure 2012-19, and which the Applicants stopped using before D.13-05-010 was issued.

126. The income tax expense presented in the Applicants' TY 2012 GRC applications, and the failure of the Applicants to disclose these changes to the Commission's attention before D.13-05-010 was issued, did not provide the Commission with an accurate forecast of the deductions for repairs that would be taken over the course of the 2012 to 2015 GRC cycle.

127. The change in accounting method was not due to productivity savings on the part of the Applicants., but instead was directly attributable to the change in accounting method authorized by the IRS.

128. If an adjustment is not made to the rate base of the Applicants, unreasonable future rates will result from the Applicants' election to change their accounting method.

129. The permanent rate base reductions that are adopted today are based on the net present value of the future excess costs to ratepayers resulting from the Applicants' tax treatment for the repairs deductions from 2011-2015, compared to the cost if no change in the repairs deduction was made until 2016.

130. The rate base reductions, as calculated by the RO model, have the effect of reducing SDG&E's revenue requirement for TY 2016 by $9.404 million ($1.624 million for gas, and $7.780 million for electric), and by $7.447 million for SoCalGas.

131. The adjustments to rate base that we adopt in today's decision will ensure that the Applicants' ratepayers will not be burdened with higher rates and costs going forward as a result of the Applicants' change in accounting method.

132. Bonus depreciation refers to a situation where a taxpayer is allowed to claim an additional amount of deductible depreciation above what is normally available, which is a form of accelerated depreciation.

133. The ratemaking effect of bonus depreciation is to increase federal tax return depreciation in the year it is taken above the regular tax depreciation provided by MACRS.

134. The difference that occurs between the bonus depreciation method, and the tax depreciation using MACRS, is accounted for in the ADIT, which is then used as an offset to reduce the rate base.

135. Bonus depreciation is an issue because it has tax implications for the Applicants' TY 2016 revenue requirement and beyond.

136. The PATH was enacted into law on December 18, 2015, which includes a provision that extends bonus depreciation for 2015 through 2019 under a phase-down schedule.

137. In the Applicants' TY 2016 GRC applications, only the ATRA and TIPA were mentioned in the testimony accompanying the applications.

138. No adjustments were made by the settling parties to reflect the extension of bonus depreciation for 2015 through the TY 2016 GRC rate cycle ending in 2018.

139. An adjustment should be made for bonus depreciation because the TY 2016 GRC applications of the Applicants only reflect bonus depreciation as a result of ATRA (tax year 2013) and TIPA (tax year 2014), but does not reflect bonus depreciation as a result of the PATH, which extended bonus depreciation for 2015 and through the TY 2016 GRC cycle.

140. If the bonus depreciation from PATH is not reflected during the TY 2016 GRC cycle for SDG&E and SoCalGas, their revenue requirements are likely to be higher and their ratepayers will pay higher rates as a result.

141. Due to the PATH, the Applicants can take advantage of the bonus depreciation for tax years 2015 through 2018, and the additional depreciation

that can be claimed is likely to have a material effect on the depreciation that can be claimed.

142. If the effects of the PATH are not reflected in the TY 2016 GRC cycle, the ADIT for TY 2016 will be lower, which will increase the amount of rate base, which in turn will result in an increase of the Applicants' return on rate base.

143. Including an adjustment to bonus depreciation for 2015 and 2016 will result in a reduction of $9.390 million to the revenue requirement of SDG&E, and a reduction of $12.784 million to the revenue requirement of SoCalGas.

144. Taxes other than taxes on income are composed of payroll taxes and ad valorem taxes.

145. As discussed in the section on taxes other than on income, the methodology agreed to by the settling parties for taxes other than income and which generated the amount of $90.874 million, is reasonable.

146. The rate base multiplied by the authorized rate of return produces the return on rate base.

147. SDG&E defines rate base "as the net investment of property, plant, equipment and other assets that SDG&E has acquired or constructed to provide utility services to its customers," while ORA's definition of rate base "is the depreciated asset value of the utility's net investments used to provide service to its customers."

148. As discussed in the section on rate base, the rate base amount of $4,976,815,000 is reasonable.

149. The provision in the Attachment 5 Settlement Agreement about working cash for the Manzanita wind project is reasonable.

150. The 7.79% rate of return reflects what the Commission approved in the TY 2013 cost of capital proceeding in D.12-12-034.

151. As discussed in the section on Rate of Return, the use of 7.79% as the rate of return in calculation of the return on rate base is reasonable.

152. Given the adopted rate base of $4,976,815,000 and rate of return of 7.79%, the TY 2016 return on rate base amount is $387.694 million.

153. The return on rate base is added to the O&M cost, depreciation, and taxes, which results in the total revenue requirement.

154. The agreement in the Attachment 5 Settlement Agreement that rates for SDG&E's customers will be adjusted on January 1, 2016 to reflect the roll-off of the GRC memorandum account balances associated with SDG&E's 2012 GRC, irrespective of the timing of a final decision in SDG&E's TY 2016 GRC, is reasonable.

155. SDG&E filed Advice Letter 2807-E on October 30, 2015 to adjust its GRC Memorandum Account to effectuate the rate stabilization agreement contained in the Attachment 5 Settlement Agreement.

156. Miscellaneous revenues are comprised of fees and revenues collected by the utility from non-rate sources for the provision of specific products or services, and include service establishment charges, collection charges, other fees, and rents.

157. As discussed in the section on miscellaneous revenues, the amount of $20.061 million is reasonable.

158. The provision to set the service establishment charge at $5.85 for all customers is reasonable.

159. Prior to the filing of the PTY Settlement Motion, SDG&E proposed a three-year GRC term of 2016-2018, and for the attrition periods of 2017 and 2018 recommended respective increases of 5.07% and 4.81%.

160. The PTY Settlement Motion provides for a 2019 attrition year, and an escalation rate of 4.3% for the 2019 attrition year.

161. The petition for modification of D.14-12-025 is being addressed in a separate decision in R.13-11-006.

162. The proposed decision in R.13-11-006, which was served on the service list in R.13-11-006 on May 6, 2016, recommends that the petition for modification of D.14-12-025 be denied.

163. The PTY Settlement Motion provides that if the two specified contingencies are not satisfied, then the PTY Settlement Agreement will be deemed null and void.

164. As discussed in this decision, the agreed upon 3.5% PTY ratemaking mechanism is reasonable.

165. As discussed in this decision, it is reasonable to continue the Z-factor mechanism without any change during the GRC cycle.

166. SoCalGas' gas distribution O&M costs consist of various activities to operate and maintain SoCalGas' pipelines and associated equipment in good working order in order to provide safe and reliable gas service to all of its customers who use natural gas.

167. Many of the gas distribution O&M costs relate to ensuring the safety and reliability of SoCalGas' gas operations and the activities relating to gas distribution are consistent with the directives in Public Utilities Code §§ 961 and 963 to develop and implement a plan for the safe and reliable operation of its gas pipelines, and to place the safety of the public and gas corporation employees as the top priority.

168. As discussed in the Gas Distribution section, the amount of $134.887 million for O&M costs is reasonable.

169. SoCalGas' capital expenditure activities for gas distribution respond to operational, maintenance, and construction needs.

170. As discussed in the capital expenditures section for gas distribution, the amounts of $247.447 million for 2014, $271.848 million for 2015, and $273.616 million for 2016, are reasonable.

171. O&M costs for gas transmission consist of the day-to-day expenses to safely operate and maintain SoCalGas' gas transmission system, and include expenses associated with pipeline operations, gas compression operations, and field engineering and technical support services.

172. As discussed in the SoCalGas gas transmission section, O&M cost of $40.877 million for gas transmission is reasonable.

173. Capital expenditures for gas transmission are for projects to enhance the efficiency and responsiveness of operations, facilitate compliance with applicable regulatory and environmental regulations and support gas transmission and storage operations to provide safe and reliable delivery of natural gas to customers at a reasonable cost.

174. As discussed in the capital expenditures section for gas transmission, the amounts of $47.059 million for 2014, $98.662 million for 2015, and $146.730 million for 2016 are reasonable.

175. SoCalGas owns and operates four underground storage fields, and the O&M costs for underground storage activities include the following: administrative and engineering costs of operating the facilities on a daily basis, including training in the areas of leadership, safety, technical, operator qualification, and quality assurance; costs associated with the routine operation of the storage reservoirs, including well testing and pressure surveys, and wellhead and down-hole activities; costs of maintaining the gas compressors and

other mechanical equipment; costs of maintaining the structures for compressor stations, and rents and royalties; and the costs associated with maintaining records for storage assets and operations.

176. The filing of the SoCalGas Settlement motion took place about six weeks before the natural gas stored at the SS-25 well of the Aliso Canyon underground gas storage facility began to leak into the atmosphere on or about October 23, 2015.

177. In November and December of 2015, the DOGGR directed SoCalGas to cease injecting natural gas into the Aliso Canyon storage field, and on May 10, 2016, SB 380 was enacted which continues the prohibition against the injection of any natural gas into the Aliso Canyon storage fields until a comprehensive review of the safety of the gas storage wells at Aliso Canyon is completed.

178. The leakage from the SS-25 well at Aliso Canyon was sealed on or about February 18, 2015.

179. None of the settling parties to the SoCalGas Settlement Motion, and none of the other parties to this proceeding, have filed any pleading in these proceedings seeking to revise the agreed upon settlement amounts for SoCalGas' underground gas storage activities.

180. Heightened scrutiny of the O&M costs and capital expenditures for underground storage is needed because of the planned activities that SoCalGas proposes to take as part of this GRC cycle, the amounts agreed to in the Attachment 1 Settlement Agreement of the SoCalGas Settlement Motion, the impact of the Aliso Canyon leak on SoCalGas' planned activities, and the fiscal impact on ratepayers of the planned O&M and capital expenditures during this GRC cycle.

181. One of the planned activities that SoCalGas plans to undertake in this GRC cycle is to establish the SIMP, which is a more proactive and in-depth approach for evaluating and managing the risks associated with the wells in its underground storage fields and is designed to collect more comprehensive data about all of SoCalGas' storage wells.

182. SIMP is different from the well inspections that have been done in the past and is attempting to get a step ahead by evaluating available information in advance of a problem that could occur.

183. In D.16-03-031, the Commission ordered SoCalGas to establish a memorandum account to track SoCalGas' authorized revenue requirement and all revenues that SoCalGas receives for its normal, business-as-usual costs to own and operate the Aliso Canyon gas storage field.

184. For TY 2016, SoCalGas' O&M request for underground storage includes $5.676 million for the SIMP activities, and SIMP-related capital expenditures of $24.272 million.

185. TURN and UCAN agreed with SoCalGas to establish a two-way balancing account for the SIMP expenditures, which is reflected in the Attachment 5 Settlement Agreement that is appended to the SoCalGas Settlement Motion.

186. Although the Aliso Canyon leak occurred during the time SoCalGas' request for the SIMP in SoCalGas' TY 2016 GRC proceeding was pending, the request for the SIMP activities is reasonable due to need to better assess the potential risks of another leak occurring.

187. As discussed in the section on underground storage, the amount of $38.381 million for the underground gas storage O&M costs, as set forth in the SoCalGas settlement agreement, is reasonable.

188. As discussed in the underground storage section, capital expenditures for underground storage of $71.069 million for 2014, $74.270 million for 2015, and $90.523 million for 2016, as agreed upon in the SoCalGas settlement agreement, are reasonable.

189. Funding the underground storage O&M costs and capital expenditures at these levels will ensure that the facilities are being maintained in good working order, and that the SIMP is carried out. All of those maintenance, mitigation, and preventative activities described in SoCalGas' testimony should enable it to prevent a similar leak from occurring in the future at its underground storage facilities.

190. The provision in the Attachment 5 settlement agreement wherein SIMP undercollections of up to 35% be recovered through the advice letter process, and undercollections above 35% be recovered through a separate proceeding, is reasonable.

191. The provision in the Attachment 5 settlement agreement that provides for the establishment of a two-way balancing account for the SIMP expenditures is reasonable.

192. The leak at Aliso Canyon also raises the issue of whether ratepayers should bear any part of the costs that have been and are being incurred as a result of the leak.

193. If some or all of the Aliso Canyon storage wells are shut down during any part of the TY 2016 GRC cycle, the memorandum account established pursuant to D.16-03-031 will allow the Commission to track, and make subject to refund, any unspent amounts that are targeted for underground storage activities.

194. The gas engineering O&M costs consist of various activities that result in providing technical guidance to support the day-to-day functions for pipeline

integrity, gas transmission, and gas distribution, including costs for TIMP and DIMP.

195. TIMP and DIMP are federally mandated pipeline integrity management programs that focus on identifying and addressing the risks to transmission and distribution pipelines.

196. As discussed in the SoCalGas engineering section, O&M costs of $131.283 million is reasonable.

197. It is reasonable to continue the two-way balancing account treatment for the TIMP and DIMP costs, and to establish a procedure to recover the undercollected amounts.

198. The SoCalGas capital expenditures for TIMP and DIMP are addressed in SoCalGas' gas engineering section.

199. As discussed in the SoCalGas capital expenditures section for engineering, the capital expenditures for TIMP and DIMP of $51.155 million for 2014, $48.637 million for 2015, and $125.184 million for 2016, are reasonable.

200. The O&M costs for procurement are for activities incurred by the Gas Acquisition Department for the procurement of natural gas on behalf of the core customers of SDG&E and SoCalGas.

201. As discussed in the SoCalGas section on procurement, the O&M gas procurement cost of $3.993 million is reasonable.

202. The customer services O&M costs cover various field, office, and information activities.

203. As discussed in the SoCalGas customer services section, the O&M cost of $338.423 million is reasonable.

204. IT O&M costs are for the provision of technology support services.

205. As discussed in the SoCalGas IT section, the O&M cost of $22.155 million is reasonable.

206. The IT capital expenditure projects are sponsored by various business units within SoCalGas, and by the IT division.

207. As discussed in the SoCalGas capital expenditures section for IT, the capital expenditures of $79.709 million for 2014, $119.916 million for 2015, and $104.796 million for 2016, are reasonable.

208. SoCalGas' support services include the following: environmental services; supply management; fleet services and facility operations; and real estate.

209. As discussed in the SoCalGas support services section, the O&M cost of $134.335 million is reasonable.

210. As discussed in the SoCalGas support services capital section, the amounts for capital expenditures of $27.628 million for 2014, $36.050 million for 2015, and $38.011 million for 2016, are reasonable.

211. Attachments 3 and 4 to the SoCalGas Settlement Motion are identical to Attachments 3 and 4 of the SDG&E Settlement Motion, and are reasonable for the reasons stated in this decision.

212. SoCalGas' A&G costs are described in various exhibits.

213. As discussed in the SoCalGas section on administrative and general, the O&M costs of $377.270 million is reasonable.

214. Attachment 2 to the SoCalGas Settlement Motion is identical to Attachment 2 of the SDG&E Settlement Motion, and is reasonable.

215. In calculating the total O&M expenses for SoCalGas, the shared services adjustments, reassignments, escalation, uncollectibles, and franchise fees, need to be taken into account.

216. As discussed in SoCalGas' shared services adjustments section, the amount of $59.188 million is reasonable.

217. As discussed in the SoCalGas section on reassignments, the amount of $87.994 million is reasonable.

218. As discussed in the SoCalGas section on escalation, the use of ORA's escalation factors, that result in the amount of $54.133 million, is reasonable.

219. As discussed in the SoCalGas section on uncollectibles, it is reasonable to use ORA's uncollectibles rate of 0.298%.

220. As discussed in the SoCalGas section on franchise fees, the use of the embedded franchise fee factor in the RO model, which results in $30.352 million, is reasonable.

221. SoCalGas' total operating expenses are derived from adding costs of depreciation and amortization, taxes on income, and taxes other than on income, to the total O&M costs.

222. As discussed in the SoCalGas section on depreciation, the agreed upon settlement amount of $403.836 million for depreciation and amortization is reasonable.

223. The income tax discussion for SoCalGas is addressed in the SDG&E section on income taxes.

224. As discussed in the SoCalGas section on taxes other than on income, the methodology agreed to by the settling parties, and which generated the amount of $95.433 million, is reasonable.

225. As discussed in the SoCalGas section on rate base, the rate base amount of $3,974,851,000 as adjusted by the repairs deduction, is reasonable.

226. The 8.02% rate of return reflects what the Commission approved in the 2013 TY cost of capital proceeding in D.12-12-034 for SoCalGas.

227. Using the agreed upon rate base amount of $4,137,633,000 and rate of return of 8.02%, results in the TY 2016 return on rate base amount of $331.838 million.

228. As discussed in the SoCalGas section on miscellaneous revenues, the amount of $99.280 million is reasonable.

229. The PTY ratemaking for SoCalGas was addressed earlier in the section addressing SDG&E's PTY ratemaking.

230. As discussed in SoCalGas' PTY ratemaking section, the PTY increases of 3.5% in 2017 and in 2018 is reasonable.

231. The extension of the AMIBA as requested by SoCalGas is reasonable.

232. It is reasonable to continue the Z-factor mechanism for SoCalGas without any change during the GRC cycle, and that portion of the SoCalGas Settlement Agreement should be adopted.

Conclusions of Law

1. To the extent that any outstanding motions or requests have not been addressed in this decision or elsewhere, those motions or requests are denied.

2. All of the oral and written rulings that the assigned Administrative Law Judges (ALJs) have issued in this proceeding are affirmed.

3. The Commission's duty and obligation under Pub. Util. Code. § 451 is to establish just and reasonable rates to enable SDG&E and SoCalGas to provide safe and reliable service, while allowing SDG&E and SoCalGas the opportunity to earn a fair return on property that companies use in providing their utility services.

4. To gain some familiarity and understanding with the reporting requirements imposed by D.14-12-025, and to obtain data and metrics on safety,

risk mitigation and accountability, the Applicants should be required to provide a limited version of the accountability reports described in D.14-12-015.

5. The one-way balancing account for the vegetation management costs should continue as provided for in the Attachment 1 Settlement Agreement to the SDG&E Settlement Motion.

6. CCUE's recommendation that spending be increases to improve or maintain the reliability of SDG&E's electric distribution is not adopted.

7. CCUE's recommendation that the capital projects for reliability and improvements be subject to a two-way balancing account is not adopted.

8. MGRA's recommendation that SDG&E should be required to develop additional metrics to justify its fire risk mitigation activities is not adopted.

9. SDG&E's proposed gas distribution activities are consistent with the directives in Pub. Util. Code §§ 961 and 963 to safely and reliably operate its gas pipelines, and to place the safety of the public and gas corporation employees as the top priority.

10. The agreed upon amount of $1.293 million in the Attachment 1 Settlement Agreement for SDG&E's nuclear generation costs should be reduced by $1.064 million to reflect the recovery by SDG&E of those offsite spent fuel storage costs in another proceeding, and as a result the nuclear generation costs should be for the amount of $229,000.

11. SDG&E's request to update its revenue requirement to reflect its 20% share of SONGS-related marine mitigation costs and escalation authorized by the Commission in SCE's TY2015 GRC is adopted, and an advice letter shall be filed for such update.

12. SDG&E should be authorized to continue the two-way SONGS balancing account through this rate cycle.

13. A two-way balancing account to recover undercollected amounts for TIMP and DIMP, as set forth in Attachment 5 of both the SDG&E and SoCalGas settlement agreements, should be adopted.

14. SDG&E's request to close or convert its downtown, National City, and Oceanside branch offices is denied without prejudice, and in accordance with the Attachment 5 Settlement Agreement, SDG&E may file a separate application to seek closure of these branch offices during this TY 2016 GRC cycle.

15. As set forth in Attachment 3 settlement agreement to the SDG&E Settlement Motion, NERBA should be established as a two-way balancing account.

16. The Attachment 3 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions should be adopted.

17. The Joint Minority Parties' advocacy activities described in the Attachment 4 Settlement Agreement are consistent with the intent of General Order 156 and Public Utilities Code §§ 8281-8286 to encourage the participation of underrepresented communities and business enterprises in the procurement of contracts from regulated utilities.

18. The pro bono work that is contemplated in the Attachment 4 settlement agreement must be related to utility issues.

19. The Attachment 4 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions should be adopted.

20. The Attachment 2 Settlement Agreement to the SDG&E and SoCalGas Settlement Motions should be adopted.

21. The July 20, 2015 data requests from the Energy Division to the Applicants are consistent with the issue identified in the February 5, 2015 scoping ruling on whether the utilities' proposed risk management, safety culture, policies, and

investments will result in the safe and reliable operations of the utilities' facilities and services.

22. The non-represented employees and executives at SDG&E and SoCalGas should not be rewarded from variable compensation for unsafe incidents.

23. SDG&E should be prevented from compensating its employees, managers, and executives from variable compensation that is based on a recovery of monies from ratepayers for the wildfire costs that are being litigated before the Commission in A.15-09-010.

24. The awarding of variable compensation that is based on a recovery of monies from ratepayers for the wildfire costs that are being litigated before the Commission in A.15-09-010 creates the perverse incentive of minimizing safety-focused incentives while benefitting employees and management by shifting the costs of unsafe incidents onto ratepayers and being rewarded for doing so.

25. SoCalGas should be prevented from awarding variable compensation to its non-represented employees and executives for its operations at its gas storage facilities or at the Aliso Canyon storage facility unless the Aliso Canyon leak is considered as a full or partial offset to such compensation.

26. Such an offset will provide a check on any variable compensation that may be awarded based on the operational performance of SoCalGas' gas storage facilities, due to the detrimental effects of the Aliso Canyon leak.

27. Pub. Util. Code § 706 supports our review of compensation expense in light of incidents that affect the safety and reliability of utility operations, and requires the electric or gas corporation in its GRC to place all authorized compensation into a balancing account, memorandum account, or other appropriate mechanism.

28. Pursuant to Pub. Util. Code § 706, SDG&E and SoCalGas should be ordered to file a Tier 2 advice letter to establish their respective Executive Compensation Memorandum Accounts as described in today's decision.

29. As a matter of law, the Commission and the gas utilities are charged with creating a culture of safety that will minimize accidents, explosions, fires, and dangerous conditions, and as a matter of policy, the Commission promotes a safety culture for all utilities and to hold them accountable for the safety of their facilities and their practices.

30. SDG&E and SoCalGas should be required to include certain testimony in their next general rate case filings as described in this decision.

31. Future reviews of the GRCs of the Applicants will be guided by and informed by the governance, safety record, and safety culture of SDG&E, SoCalGas, and Sempra, as well as their actions with respect to the awarding of compensation, bonuses, severances, or any other benefit as a result of unsafe incidents such as wildfires, leakage from gas storage, and similar types of incidents.

32. Irrespective of any other pending or future proceeding, SoCalGas and Sempra are placed on notice that we intend to scrutinize their management and governance that preceded, coincided with, and which followed the leak at the Aliso Canyon storage facility.

33. SoCalGas and Sempra should exercise its discretion, and its authority under the applicable code sections, to withhold, deny, or claw back compensation, bonuses, severances, or any other benefit, relating to the operation, management, and oversight of Aliso Canyon.

34. During the TY 2016 GRC cycle, the assigned Commissioner's office may request the staff of SED or the Energy Division to issue data requests of SDG&E

and SoCalGas to provide further information regarding the operations and policies of the utilities, and the interrelationship with Sempra.

35. The settling parties recognize that the outcome of the repairs deduction issue may alter the revenue requirement amount agreed to by the settling parties in the SDG&E Settlement Motion and the SoCalGas Settlement Motion.

36. Had the change in accounting method been forecasted as part of the Applicants' TY 2012 GRC proceedings, the income tax savings would have flowed to ratepayers, instead of to shareholders, which is an unjust result under the circumstances.

37. For the reasons stated in today's decision, a permanent adjustment to the rate base of SoCalGas and SDG&E is warranted due to the change in accounting method for the repairs deduction.

38. Official notice is taken of Sempra's Form 10-Q Quarterly Report, filed with the SEC on November 6, 2012, which discussed the decrease in income tax expense due primarily to a change in the income tax treatment of certain repairs.

39. One could argue that the Applicants' failure to bring these material differences to the attention of the Commission should be considered a violation of Rule 1 of the Commission's Rules of Practice and Procedures.

40. Under the circumstances, the rate base reductions that we adopt in today's decision, does not amount to retroactive ratemaking.

41. D.13-05-010 never reviewed or considered the changes in the accounting method that the Applicants pursued during the timeframe when the TY 2012 GRC applications were still pending before the Commission.

42. To allow this material change to escape the Commission's review merely because of the Applicants' timing of the tax change, and the Applicants' failure

to bring this material change to the attention of the Commission, would be unjust and unreasonable under the circumstances.

43. Retroactive ratemaking and Pub. Util. Code § 728 do not apply to the facts of these events, and do not prevent us from making the adjustments for the repairs deduction.

44. To allow the Applicants to pocket the income tax savings resulting from the changes to their accounting methods would be inequitable under the circumstances, and the Commission should take action to rectify this result, which would have resulted in a flow-through of benefits to ratepayers had the change in accounting method been considered in the TY 2012 GRC applications.

45. The Commission has the regulatory authority to order a rate base reduction to compensate for the undisclosed decrease in the future long-term depreciable basis.

46. Today's adjustment to the repairs deduction is consistent with, and does not violate the normalization rules.

47. The prospective adjustment that is adopted in today's decision to permanently reduce the rate base of SDG&E and SoCalGas is just and reasonable under the circumstances, and does not result in retroactive ratemaking.

48. For TY 2016, an adjustment for the period from 2016 through 2042 is warranted to recognize the long term impact on future rates from the changes to the Applicants' accounting methods which were never disclosed to the Commission during the pendency of their TY 2012 GRC applications.

49. The California Supreme Court has recognized that the Commission may make adjustments for taxes that have not actually been paid, and to protect against unreasonably inflated tax expense.

50. If an adjustment for the repairs deduction is not made, the Commission would not be fulfilling its duty under Pub. Util. Code § 451 to ensure that all charges demanded or received by any public utility are just and reasonable.

51. The prospective adjustment that we adopt today is consistent with and does not violate Pub. Util. Code § 728 because hearings were held in this proceeding, and testimony was presented by the parties regarding the deduction for repairs.

52. The Applicants shall be directed to notify the Commission of any tax-related changes, any tax-related accounting changes, or any tax-related procedural changes that materially affect, or may materially affect, revenues and establish a memorandum account to track any revenue differences if applicable.

53. "Materially affect" means $3 million or more.

54. Since the Attachment 1 Settlement Agreement for both SDG&E and SoCalGas does not address the extension of bonus depreciation, that provision of the SDG&E settlement and the SoCalGas settlement is unreasonable and not in the public interest because of the Applicants' ability to use bonus depreciation for the tax years of 2015 through 2018, and that portion of the settlement agreement should be rejected.

55. Official notice is taken of Sempra's 2015 Annual Report, and its Form 10-K filing with the SEC on February 26, 2016, both of which reflects the actions that the Applicants took with respect to bonus depreciation in tax year 2015.

56. To ignore the effects of the PATH, when the Applicants have applied bonus depreciation for 2015, and presumably will do so for tax year 2016, would be unreasonable and not in the public interest because of the effect on the revenue requirements and the rates that ratepayers will have to pay.

57. The Commission should adopt an adjustment to the TY 2016 revenue requirements of SDG&E and SoCalGas that reflects the inclusion of bonus depreciation for tax years 2015 and 2016.

58. An adjustment to the TY 2016 revenue requirements of SDG&E and SoCalGas for bonus depreciation is consistent with the Rate Case Plan in which known changes in the tax laws should be reflected, and the Commission should exercise its discretion to take into account the change in the tax law.

59. The provision in the Attachment 5 Settlement Agreement about working cash for the Manzanita wind project should be adopted.

60. The provision in the Attachment 5 Settlement Agreement to set SDG&E's service establishment charge for all customers at $5.85 should be adopted.

61. Consistent with the outcome expected in R.13-11-006, this decision denies the PTY Settlement Motion to adopt the PTY Settlement Agreement.

62. The agreed upon 3.5% PTY ratemaking mechanism should be adopted for each of the attrition years.

63. The agreement to continue the Z-factor mechanism without any change during the GRC cycle for SDG&E should be adopted.

64. The Z-factor mechanism for both SDG&E and SoCalGas apply to cost decreases, as well as cost increases.

65. Except for the settling parties agreement with respect to bonus depreciation, and the SONGS offsite storage costs, we conclude that the five settlements attached to the SDG&E Settlement Motion are reasonable, in the public interest, and consistent with the law.

66. The SDG&E Settlement Motion to adopt the five settlements should be granted, and the five settlements attached to the SDG&E Settlement Motion, excluding the exceptions discussed in today's decision, should be adopted.

67. Due to the provision in the Attachment 5 Settlement Agreement about the tax issue involving the deduction of repairs, and the adjustments we make for bonus depreciation, and the SONGS offsite storage costs, today's decision should adopt a TY 2016 revenue requirement of $1,789,286,000 for the combined operations of SDG&E.

68. The PTY Settlement Motion should be denied.

69. Many of SoCalGas' gas distribution O&M activities are consistent with the directives in Pub. Util. Code §§ 961 and 963 to develop and implement a plan for the safe and reliable operation of its gas pipelines, and to place the safety of the public and gas corporation employees as the top priority.

70. A two-way balancing account for SIMP undercollections should be established.

71. The agreement in the Attachment 5 settlement agreement wherein SIMP undercollections of up to 35% be recovered through the advice letter process, and undercollections above 35% be recovered through a separate proceeding, should be adopted.

72. UWUA's recommendation for a working group to discuss and implement SIMP activities is not adopted.

73. This GRC proceeding is looking at the funding needs over the GRC cycle, and is not focusing into what may have caused the Aliso Canyon leak, and whether authorized underground storage expenditures in the past should have prevented the leak from occurring.

74. The provision in the Attachment 5 settlement agreement to institute a two-way balancing account procedure for the SIMP expenditures is reasonable, and that provision of the Attachment 5 settlement agreement should be adopted.

75. The Aliso Canyon leak opens the door for the Commission to open another proceeding to look into the cause of the Aliso Canyon leak and whether the leak could have been prevented as a result of past expenditures authorized for underground storage activities.

76. Until SED's investigation and report on the Aliso Canyon leak is finished, it is premature for the Commission to open an Order Instituting Investigation into the causes of the Aliso Canyon leakage, whether past expenditures were appropriately spent to detect these kinds of problems, and whether SoCalGas' ratepayers should bear any responsibility for the various costs incurred as a result of the leakage at Aliso Canyon.

77. SoCalGas should be required in its next GRC filing, to provide a separate itemization of all of the costs related to the gas leak at the SS-25 well at Aliso Canyon and to provide testimony on whether the costs attributable to the Aliso Canyon leak have affected SoCalGas' funding request for its underground gas storage facilities.

78. The provision in SoCalGas' Attachment 5 Settlement Agreement to continue to maintain separate two-way balancing accounts for the TIMP and DIMP expenditures, and the agreed on the process for recovery of undercollected amounts, should be approved.

79. For the reasons stated in this decision, Attachments 3 and 4 of the SoCalGas Settlement Motion should be adopted.

80. For the reasons stated in this decision, the Attachment 2 Settlement Agreement to the SoCalGas Settlement Motion should be adopted.

81. The extension of the AMIBA as requested by SoCalGas should be adopted.

82. The settlement agreements in the SoCalGas Settlement Motion requesting that the Z-factor mechanism be continued without any change during the GRC cycle, should be adopted.

83. Except for the settling parties agreement with respect to bonus depreciation, we conclude that the five settlements attached to the SoCalGas Settlement Motion are reasonable, in the public interest, and consistent with the law.

84. The SoCalGas Settlement Motion to adopt the five settlements should be granted, and the five settlements attached to the SoCalGas Settlement Motion, excluding the exception for bonus depreciation discussed in today's decision, should be adopted.

85. Due to the provision in the Attachment 5 Settlement Agreement about the tax issue involving the deduction of repairs, and the adjustments we make for bonus depreciation, today's decision should adopt a TY 2016 revenue requirement of $2,199,194,000 for SoCalGas.

O R D E R

IT IS ORDERED that:

1. The September 11, 2015 "Joint Motion For Adoption of Settlement Agreements Regarding San Diego Gas & Electric Company's Test Year 2016 General Rate Case, Including Attrition Years 2017 and 2018" (SDG&E Settlement Motion) is granted, and except for the three adjustments to the Test Year 2016 revenue requirement for San Diego Gas & Electric Company (SDG&E) as noted below, the five settlement agreements attached to the SDG&E Settlement Motion, are adopted.

a. In the Attachment 1 settlement agreement to the SDG&E Settlement Motion, the provision regarding bonus depreciation is not adopted, and an adjustment is made to the adopted revenue requirement for bonus depreciation.

b. In the Attachment 1 settlement agreement to the SDG&E Settlement Motion, the provision regarding the offsite spent fuel storage costs for the San Onofre Nuclear Generating Station in the amount of $1.064 million is not adopted, and an adjustment is made to the adopted revenue requirement to remove that amount.

c. As set forth in the Attachment 5 settlement agreement to the SDG&E Settlement Motion, the settling parties agreed that the issue regarding the deduction of repairs would be litigated separately, and an adjustment has been made to the rate base of SDG&E for the change in accounting method for the repairs deduction that SDG&E used.

d. With the three adjustments referenced above, a Test Year 2016 revenue requirement of $1,789,286,000 for the combined operations ($1,482,033,000 for electric operations, and $307,253,000 for gas operations) of SDG&E is adopted.

    i. Pursuant to Decision 15-05-044, the adopted Test Year 2016 revenue requirement is effective January 1, 2016, and shall be amortized over a 12 month period beginning August 1, 2016.

    ii. Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, since two of the three adjustments to the adopted revenue requirement are addressed within the Attachment 1 settlement agreement to the SDG&E Settlement Motion, the settling parties shall have 15 days from today's date to file with the Docket Office, and serve, a "Notice To Accept SDG&E's Adopted Test Year 2016 Revenue Requirement," or to file a "Motion Requesting Other Relief."

    iii. In the event a "Motion Requesting Other Relief" is filed, parties may respond to the motion as provided for in Rule 11.1. The adopted Test Year 2016 revenue requirement for SDG&E shall remain in effect until a decision resolving the request for other relief is adopted by the Commission.

e. Within 15 days from the effective date of this Order, SDG&E shall file a Tier 1 Advice Letter, with revised tariff sheets, to implement the Test Year 2016 revenue requirement authorized by this Ordering Paragraph 1.

   i. The revised tariff sheets shall become effective on August 1, 2016, subject to a finding of compliance by the Commission's Energy Division, and compliance with General Order 96-B.

   ii. The balances recorded in SDG&E's General Rate Case Revenue Requirement Memorandum Account from January 1, 2016 until the effective date of the new tariffs required by this Ordering Paragraph, shall be amortized in rates beginning August 1, 2016 through July 31, 2017.

2. The September 11, 2015 "Joint Motion For Adoption of Settlement Agreements Regarding Southern California Gas Company's Test Year 2016 General Rate Case, Including Attrition Years 2017 and 2018" (SoCalGas Settlement Motion) is granted, and except for the two adjustments to the Test Year 2016 revenue requirement for Southern California Gas Company (SoCalGas) as noted below, the five settlement agreements attached to the SoCalGas Settlement Motion, are adopted.

a. In the Attachment 1 settlement agreement to the SoCalGas Settlement Motion, the provision regarding bonus depreciation is not adopted, and an adjustment is made to the adopted revenue requirement for bonus depreciation.

b. As set forth in the Attachment 5 settlement agreement to the SoCalGas Settlement Motion, the settling parties agreed that the issue regarding the deduction of repairs would be litigated separately, and an adjustment has been made to the rate base of SoCalGas for the change in accounting method for the repairs deduction that SoCalGas used.

c. With the two adjustments referenced above, a Test Year 2016 revenue requirement of $2,199,194,000 for SoCalGas is adopted.

i. Pursuant to Decision 15-05-044, the adopted Test Year 2016 revenue requirement is effective January 1, 2016, and shall be amortized over a 12 month period beginning August 1, 2016.

ii. Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, since one of the two adjustments to the adopted revenue requirement is addressed within the Attachment 1 settlement agreement to the SoCalGas Settlement Motion, the settling parties shall have 15 days from today's date to file with the Docket Office, and serve, a "Notice To Accept SoCalGas' Adopted Test Year 2016 Revenue Requirement," or to file a "Motion Requesting Other Relief."

iii. In the event a "Motion Requesting Other Relief" is filed, parties may respond to the motion as provided for in Rule 11.1. The adopted Test Year 2016 revenue requirement for SoCalGas shall remain in effect until a decision resolving the request for relief is adopted by the Commission.

d. Within 15 days from the effective date of this Order, SoCalGas shall file a Tier 1 Advice Letter, with revised tariff sheets, to implement the Test Year 2016 revenue requirement authorized by this Ordering Paragraph 2.

i. The revised tariff sheets shall become effective on August 1, 2016, subject to a finding of compliance by the Commission's Energy Division, and compliance with General Order 96-B.

ii. The balances recorded in SoCalGas' General Rate Case Revenue Requirement Memorandum Account from January 1, 2016 until the effective date of the new tariffs required by this Ordering Paragraph, shall be amortized in rates beginning August 1, 2016 through July 31, 2017.

3. San Diego Gas & Electric Company, and Southern California Gas Company, shall each file a Tier 1 advice letter within 30 days of the effective date of this decision to flow-through to ratepayers the balance in the memorandum

account, effective January 15, 2015, to track the differences associated with changes in the repairs deduction.

4. San Diego Gas & Electric Company, and Southern California Gas Company, shall each file a Tier 2 advice letter within 30 days of the effective date of this decision to establish a tax memorandum account to record any revenue differences resulting from the income tax expenses forecasted in their GRC proceedings, and the tax expenses incurred by the utilities during the GRC period.

5. San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas), are each directed to submit a request for a private letter ruling to the Internal Revenue Service (IRS) to ensure that the rate base reductions adopted in today's decision does not violate the IRS normalization rules.

   a. Before submitting the private letter ruling to the IRS, SDG&E and SoCalGas shall each file a Tier 2 advice letter attaching the draft of the request for a private letter ruling to provide the Commission with an opportunity to review the draft to ensure that the facts and circumstances set forth in the request are correct.

   b. SDG&E and SoCalGas shall file this Tier 2 advice letter within 90 days of the effective date of this decision.

6. The request of San Diego Gas & Electric Company (SDG&E) that it be allowed to update its revenue requirement to reflect its 20% share of the marine mitigation and escalation costs related to the San Onofre Nuclear Generating Station that was authorized in Decision 15-11-021, is granted.

   a. SDG&E shall file such an update in a Tier 1 advice letter within 15 days from today's date.

7. The request of San Diego Gas & Electric Company (SDG&E) to close or convert the three named branch offices is denied without prejudice.

   a. In accordance with the Attachment 5 settlement agreement to the SDG&E Settlement Motion, SDG&E may file a separate application to seek closure or to convert the three named branch offices during the Test Year 2016 general rate case cycle.

8. San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas), are authorized to do the following with regard to the balancing accounts discussed in today's decision: (a) the one-way balancing account for SDG&E's vegetation management costs shall continue as provided for in the Attachment 1 Settlement Agreement to the SDG&E Settlement Motion; (b) SDG&E shall continue the two-way balancing account for San Onofre Nuclear Generating Station through this rate cycle; (c) continue the two-way balancing account to recover undercollected amounts for the Transmission Integrity Management Program and the Distribution Integrity Management Program, as set forth in Attachment 5 of both the SDG&E and SoCalGas settlement agreements; (d) as set forth in Attachment 3 settlement agreement to the SDG&E and SoCalGas Settlement Motions, the New Environmental Regulatory Balancing Account shall be established as a two-way balancing account; (e) as set forth in the Attachment 2 settlement agreement for both SDG&E and SoCalGas, the current balancing account treatment for the Pension Balancing Account, and the Post-Retirement Benefits Other Than Pension Balancing Account, shall remain unchanged; (f) SoCalGas shall establish a two-way balancing account for the Storage Integrity Management Program undercollections; and (g) the Advanced Metering Infrastructure Balancing Account for SoCalGas shall be continued.

9. Pursuant to Public Utilities Code Section 706, San Diego Gas and Electric Company (SDG&E), and Southern California Gas Company (SoCalGas), shall

within 45 days of today's date, file Tier 2 advice letters to establish their respective "Executive Compensation Memorandum Account."

a. The memorandum account shall track all monies authorized in today's decision for the annual salaries, bonuses, benefits, and all other consideration of any value, set aside to be paid to the officers of the utility, and to track that against the salaries, bonuses, benefits, and all other consideration of any value, paid to its officers.

b. The advice letters establishing the memorandum accounts shall define the "officers" of each company who are subject to the provisions of Public Utilities Code Section 706.

c. SDG&E and SoCalGas shall follow the requirements of Public Utilities Code Section 706 if it seeks to have ratepayers pay for the "excess compensation" that may have been paid to or owed to an officer in connection with a "triggering event."

10. San Diego Gas & Electric Company (SDG&E) is prohibited from compensating its employees, managers, and executives from variable compensation that is based on SDG&E's recovery of monies from ratepayers for the wildfire costs that are being litigated before the Commission in Application 15-09-010.

a. Any "excess compensation" that may be paid in the future to an SDG&E "officer" may be subject to Public Utilities Code Section 706.

11. Southern California Gas Company shall not award its employees, managers, and executives from variable compensation for the operational performance of its underground storage facilities unless it has taken into consideration as a full of partial offset the detrimental effects of the Aliso Canyon leak.

a. Pursuant to Public Utilities Code Section 706, any "excess compensation" paid to an "officer" is subject to the provisions of this code section.

12. San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas), shall file on an interim basis a limited version of the two accountability reports specified in Decision 14-12-015.

   a. SDG&E and SoCalGas shall each file a Spending Accountability Report with the Docket Office, and serve a notice of availability of such report as directed in this decision, within one year from the issuance date of today's decision.

      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 as discussed in this decision and in Exhibit 23, and to propose a methodology for reporting and comparing the projected versus actual benefits of its risk mitigation activities.

   b. A second Spending Accountability Report shall be filed and served within two years from the issuance of today's decision, which is to include actual 2016 spending.

   c. SDG&E and SoCalGas are directed to discuss the format of these reports with the Safety and Enforcement Division and the Energy Division on the format of such reports before the due dates of these reports.

   d. Subsequent reporting requirements beyond what is required above will be supplanted by the direction provided in Decision 14-12-025, a decision in either or both the Safety Model Assessment Proceeding and Risk Assessment Mitigation Phase, or in the next general rate case proceedings of the Applicants.

13. In its Test Year 2019 general rate case application, Southern California Gas Company shall provide testimony demonstrating that all of the additional costs that stemmed from the Aliso Canyon leak have not been included in its forecast of costs for its Test Year 2019 general rate case application.

14. The September 11, 2015 "Joint Motion of San Diego Gas & Electric Company, Southern California Gas Company and Office of Ratepayer Advocates

for Adoption of Settlement Agreement Regarding the Post-Test Year Period" is denied.

15. Application (A.) 14-11-003 shall be closed following the filing of a "Notice To Accept SDG&E's Adopted Test Year 2016 Revenue Requirement."

    a. In the event a "Motion Requesting Other Relief" is filed in connection with A.14-11-003, A.14-11-003 shall remain open until a decision or ruling resolves the motion, and the issue raised by this motion shall extend the time for resolving this matter by another 18 months as provided for in Public Utilities Code Section 1701.5.

16. Application (A.) 14-11-004 shall be closed following the filing of a "Notice To Accept SoCalGas' Adopted Test Year 2016 Revenue Requirement."

    a. In the event a "Motion Requesting Other Relief" is filed in connection with A.14-11-003, A.14-11-003 shall remain open until a decision or ruling resolves the motion, and the issue raised by this motion shall extend the time for resolving this matter by another 18 months as provided for in Public Utilities Code Section 1701.5.

This order is effective today.

Dated ____________________________, at San Francisco, California.

APPENDIX A

RESULTS OF OPERATION MODEL
SOUTHERN CALIFORNIA GAS COMPANY
TEST YEAR 2016
SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Request) (2016$)
1	Base Margin		$ 2,230,627	$ 2,120,146	$ 2,100,510	$ (130,117)
2	Miscellaneous Revenues		100,561	99,280	98,685	(1,876)
3	Revenue Requirement		$ 2,331,187	$ 2,219,426	$ 2,199,194	$ (131,993)
	Operating and Maintenance Expenses					
4	Gas Distribution		144,989	134,887	134,887	(10,102)
5	Transmission		40,867	40,877	40,877	10
6	Underground Storage		40,182	38,381	38,381	(1,801)
7	Engineering		131,284	131,283	131,283	(1)
8	PSEP		-	-	-	
9	Procurement		3,993	3,993	3,993	-
10	Customer Services		356,620	338,423	338,423	(18,197)
11	Information Technology		23,624	22,155	22,155	(1,469)
12	Support Services		140,190	134,335	134,335	(5,855)
13	Administrative and General		433,618	377,270	377,267	(56,351)
14	Subtotal (2013$)		$ 1,315,366	$ 1,221,604	$ 1,221,601	$ (93,765)
15	Shared Services Adjustments		59,829	59,188	59,188	(640)
16	Reassignments		(98,668)	(87,994)	(87,994)	10,674
17	Escalation		58,088	54,133	54,133	(3,955)
18	Uncollectibles (0.298%)		6,824	6,195	6,138	(686)
19	Franchise Fees (1.4136%)		31,905	30,352	30,075	(1,830)
20	Total O&M (2016$)		$ 1,373,344	$ 1,283,479	$ 1,283,141	$ (90,204)
21	Depreciation		409,557	403,836	403,836	(5,721)
22	Taxes on Income		109,240	104,839	98,486	(10,754)
23	Taxes Other Than on Income		99,544	95,433	94,948	(4,596)
24	Total Operating Expenses		1,991,686	1,887,587	1,880,411	(111,275)
25	Return		339,501	331,838	318,783	(20,718)
26	Rate Base		4,233,180	4,137,633	3,974,851	(258,330)
27	Rate of Return		8.02%	8.02%	8.02%	0.00%
28	Derivation of Base Margin					
29	O&M Expenses	(Line 19)	1,373,344	1,283,479	1,283,141	(90,204)
30	Depreciation	(Line 20)	409,557	403,836	403,836	(5,721)
31	Taxes	(Line 21+22)	208,784	200,272	193,434	(15,350)
32	Return	(Line 24)	339,501	331,838	318,783	(20,718)
33	Revenue Requirement		2,331,187	2,219,426	2,199,194	(131,993)
34	Less: Miscellaneous Revenues	(Line 2)	100,561	99,280	98,685	(1,876)
35	Base Margin	(Line 1)	$ 2,230,627	$ 2,120,146	$ 2,100,510	$ (130,117)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
COMBINED SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Reques (2016$)
1	Base Margin		$ 1,876,202	$ 1,790,472	1,769,228	$ (106,974)
2	Miscellaneous Revenues		19,235	20,061	20,057	822
3	Revenue Requirement		$ 1,895,437	$ 1,810,533	1,789,286	$ (106,151)
	OPERATING & MAINTENANCE EXPENSES					
4	Distribution		159,348	150,756	150,756	(8,592)
5	Gas Transmission		4,631	4,663	4,663	32
6	PSEP		-	-	-	-
7	Generation		54,415	53,333	53,333	(1,082)
8	Nuclear Generation (SONGS)		1,293	1,293	229	(1,064)
9	Engineering		12,294	11,919	11,919	(375)
10	Procurement		8,757	8,757	8,757	-
11	Customer Services		89,628	85,448	85,448	(4,180)
12	Information Technology		109,115	106,368	106,368	(2,747)
13	Support Services		105,627	102,961	102,961	(2,666)
14	Administrative and General		431,532	388,342	387,760	(43,772)
15	Subtotal (2013$)		976,640	913,840	912,194	(64,446)
16	Shared Services Adjustments		(91,061)	(90,216)	(90,216)	845
17	Reassignments		(127,510)	(114,924)	(114,924)	12,586
18	FERC Transmission Costs		(60,446)	(55,666)	(55,593)	4,853
19	Escalation		22,245	21,172	21,172	(1,073)
20	Uncollectibles		3,263	3,114	3,077	(186)
21	Franchise Fees		59,965	57,215	56,531	(3,434)
22	Total O&M (2016$)		783,096	734,536	732,241	(50,855)
23	Depreciation & Amortization		439,813	432,059	432,059	(7,754)
24	Taxes on Income		163,233	152,735	146,418	(16,815)
25	Taxes Other Than on Income		94,746	91,325	90,874	(3,872)
26	Total Operating Expenses		$ 1,480,889	$ 1,410,655	1,401,592	$ (79,297)
27	Return		414,548	399,878	387,694	(26,854)
28	Rate Base		5,321,539	5,133,222	4,976,815	(344,724)
29	Rate of Return		7.79%	7.79%	7.79%	0.00%
30	Derivation of Base Margin					
31	O&M Expenses	(Line 21)	$ 783,096	$ 734,536	$732,241	$ (50,855)
32	Depreciation	(Line 22)	439,813	432,059	432,059	(7,754)
33	Taxes	(Line 23+24)	257,979	244,060	237,292	(20,687)
34	Return	(Line 26)	414,548	399,878	387,694	(26,854)
35	Revenue Requirement		1,895,437	1,810,533	1,789,286	(106,151)
36	Less: Misc. Revenues	(Line 2)	19,235	20,061	20,057	822
37	Base Margin	(Line 1)	$ 1,876,202	$ 1,790,472	$1,769,228	$ (106,974)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
ELECTRIC SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Reques (2016$)
1	Base Margin		$ 1,556,022	$ 1,484,192	$ 1,466,181	$ (89,841)
2	Miscellaneous Revenues		15,227	15,854	15,852	625
3	Revenue Requirement		$ 1,571,249	$ 1,500,046	$ 1,482,033	$ (89,216)
	OPERATING & MAINTENANCE EXPENSES					
4	Distribution		134,150	126,760	126,760	(7,390)
5	Gas Transmission		-	-	-	-
6	PSEP		-	-	-	-
7	Generation		53,864	52,802	52,802	(1,062)
8	Nuclear Generation (SONGS)		1,293	1,293	229	(1,064)
9	Engineering		584	330	330	(254)
10	Procurement		8,647	8,647	8,647	(0)
11	Customer Services		57,485	53,986	53,986	(3,499)
12	Information Technology		80,735	78,625	78,625	(2,110)
13	Support Services		82,418	80,316	80,316	(2,102)
14	Administrative and General		346,516	313,829	313,394	(33,122)
15	Subtotal (2013$)		765,691	716,589	715,089	(50,602)
16	Shared Services Adjustments		(72,605)	(71,855)	(71,855)	750
17	Reassignments		(97,510)	(88,022)	(88,022)	9,488
18	FERC Transmission Costs		(60,446)	(55,666)	(55,593)	4,853
19	Escalation		15,688	15,044	15,044	(644)
20	Uncollectibles (0.174%)		2,706	2,581	2,550	(156)
21	Franchise Fees (3.4273%)		53,328	50,867	50,249	(3,079)
22	Total O&M (2016$)		606,853	569,538	567,463	
23	Depreciation & Amortization		382,132	374,980	374,980	(7,152)
24	Taxes on Income		143,633	133,676	128,373	(15,260)
25	Taxes Other Than on Income		79,765	76,726	76,337	(3,428)
26	Total Operating Expenses		$ 1,212,382	$ 1,154,921	$1,147,153	$ (65,229)
27	Return		358,867	345,125	334,880	(23,987)
28	Rate Base		4,606,766	4,430,365	4,298,839	(307,927)
29	Rate of Return		7.79%	7.79%	7.79%	0.00%
30	Derivation of Base Margin					
31	O&M Expenses	(Line 21)	$ 606,853	$ 569,538	$567,463	$ (39,390)
32	Depreciation	(Line 22)	382,132	374,980	374,980	(7,152)
33	Taxes	(Line 23+24)	223,397	210,402	204,710	(18,687)
34	Return	(Line 26)	358,867	345,125	334,880	(23,987)
35	Revenue Requirement		1,571,249	1,500,046	1,482,033	(89,216)
36	Less: Misc. Revenues	(Line 2)	15,227	15,854	15,852	625
37	Base Margin	(Line 1)	$ 1,556,022	$ 1,484,192	$1,466,181	$ (89,841)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
ELECTRIC DISTRIBUTION SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony Excl. Legacy Meter (2016$)	Update Testimony Legacy Meter* (2016$)	Settlement Incl. Legacy Meter (2016$)	Adopted CPUC Total Incl. Legacy Meter (2016$)	Difference CPUC Total Incl. Legacy Meter (2016$)
1	Base Margin		$ 1,323,463	$ 18,774	$ 1,274,425	$1,257,945	$ (84,292)
2	Miscellaneous Revenues		15,227	-	15,854	15,852	625
3	Revenue Requirement		$ 1,338,690	$ 18,774	$ 1,290,279	$1,273,797	$ (83,667)
	OPERATING & MAINTENANCE EXPENSES						
4	Distribution		133,645		126,294	126,294	(7,351)
5	Gas Transmission		-		-	-	-
6	PSEP						
7	Generation		1,634		1,561	1,561	(73)
8	Nuclear Generation (SONGS)		-		-	-	-
9	Engineering		576		327	327	(249)
10	Procurement		8,634		8,634	8,634	0
11	Customer Services		57,447		53,948	53,948	(3,499)
12	Information Technology		77,626		75,619	75,619	(2,007)
13	Support Services		80,307		78,218	78,218	(2,089)
14	Administrative and General		335,515		304,121	303,704	(31,811)
15	Subtotal (2013$)		695,385	-	648,721	648,304	(47,081)
16	Shared Services Adjustments		(69,480)		(68,770)	(68,770)	710
17	Reassignments		(94,166)		(84,668)	(84,668)	9,498
18	FERC Transmission Costs		(60,446)		(55,666)	(55,593)	4,853
19	Escalation		14,101		13,284	13,284	(817)
20	Uncollectibles		2,303	32	2,216	2,188	(146)
21	Franchise Fees		45,359	642	43,677	43,112	(2,889)
22	Total O&M (2016$)		533,055	674	498,795	497,857	(35,872)
23	Depreciation & Amortization		320,877	18,100	332,019	332,019	(6,958)
24	Taxes on Income		112,028		102,584	97,404	(14,624)
25	Taxes Other Than on Income		67,135		64,147	63,777	(3,358)
26	Total Operating Expenses		$ 1,033,096	$ 18,774	$ 997,545	$991,057	$ (60,813)
27	Return		305,594	-	292,734	282,740	(22,854)
28	Rate Base		$ 3,922,901	$ -	$ 3,757,819	$3,629,523	$ (293,378)
29	Rate of Return		7.79%	0.00%	7.79%	7.79%	0.00%
							0
30	Derivation of Base Margin						-
31	O&M Expenses	(Line 21)	$ 533,055	$ 674	$ 498,795	$497,857	$ (35,872)
32	Depreciation	(Line 22)	320,877	18,100	332,019	332,019	(6,958)
33	Taxes	(Line 23+24)	179,164	-	166,731	161,181	(17,983)
34	Return	(Line 26)	305,594	-	292,734	282,740	(22,854)
35	Revenue Requirement		1,338,690	18,774	1,290,279	1,273,797	(83,667)
36	Less: Misc. Revenues	(Line 2)	15,227	-	15,854	15,852	625
37	Base Margin	(Line 1)	$ 1,323,463	$ 18,774	$ 1,274,425	$1,257,945	$ (84,292)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
GENERATION SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Reque (2016$)
1	Base Margin		$ 210,441	$ 206,423	$ 206,172	$ (4,269)
2	Miscellaneous Revenues		-	-	-	-
3	Revenue Requirement		$ 210,441	$ 206,423	$ 206,172	$ (4,269)
	OPERATING & MAINTENANCE EXPENSES					
4	Distribution		505	466	466	(39)
5	Gas Transmission		-	-	-	-
6	PSEP		-	-	-	-
7	Generation		52,229	51,241	51,241	(988)
8	Nuclear Generation (SONGS)		-	-	-	-
9	Engineering		8	3	3	(5)
10	Procurement		13	13	13	-
11	Customer Services		38	38	38	-
12	Information Technology		3,109	3,007	3,007	(102)
13	Support Services		2,111	2,098	2,098	(13)
14	Administrative and General		11,000	9,709	9,691	(1,310)
15	Subtotal (2013$)		69,014	66,575	66,557	(2,457)
16	Shared Services Adjustments		(3,125)	(3,085)	(3,085)	40
17	Reassignments		(3,344)	(3,354)	(3,354)	(10)
18	FERC Transmission Costs		-	-	-	-
19	Escalation		1,587	1,760	1,760	173
20	Uncollectibles		366	359	359	(7)
21	Franchise Fees		7,212	7,075	7,066	(146)
22	Total O&M (2016$)		71,710	69,330	69,303	(2,407)
23	Depreciation & Amortization		42,301	42,108	42,108	(194)
24	Taxes on Income		31,277	30,764	30,695	(582)
25	Taxes Other Than on Income		12,564	12,514	12,504	(60)
26	Total Operating Expenses		$ 157,853	$ 154,716	$ 154,609	$ (3,244)
27	Return		52,588	51,706	51,563	(1,025)
28	Rate Base		$ 675,072	$ 663,754	$ 661,909	$ (13,162)
29	Rate of Return		7.79%	7.79%	7.79%	0.00%
30	Derivation of Base Margin					
31	O&M Expenses	(Line 21)	$ 71,710	$ 69,330	$ 69,303	$ (2,407)
32	Depreciation	(Line 22)	42,301	42,108	42,108	(194)
33	Taxes	(Line 23+24)	43,841	43,279	43,199	(642)
34	Return	(Line 26)	52,588	51,706	51,563	(1,025)
35	Revenue Requirement		210,441	206,423	206,172	(4,269)
36	Less: Misc. Revenues	(Line 2)	-	-	-	-
37	Base Margin	(Line 1)	$ 210,441	$ 206,423	$ 206,172	$ (4,269)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
SONGS SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Request (2016$)
1	Base Margin		$ 3,344	$ 3,344	$2,064	$ (1,280)
2	Miscellaneous Revenues		-	-	-	-
3	Revenue Requirement		$ 3,344	$ 3,344	$2,064	$ (1,280)
	OPERATING & MAINTENANCE EXPENSES					
4	Distribution					
5	Gas Transmission					
6	PSEP					
7	Generation					
8	Nuclear Generation (SONGS)		1,293	1,293	229	(1,064)
9	Engineering					
10	Procurement					
11	Customer Services					
12	Information Technology					
13	Support Services					
14	Administrative and General		-	-	-	-
15	Subtotal (2013$)		1,293	1,293	229	(1,064)
16	Shared Services Adjustments					
17	Reassignments		-	-	-	-
18	FERC Transmission Costs		-	-	-	-
19	Escalation		-	-	-	-
20	Uncollectibles		6	6	4	(2)
21	Franchise Fees		115	115	71	(44)
22	Total O&M (2016$)		1,413	1,413	303	(1,110)
23	Depreciation & Amortization		853	853	853	(0)
24	Taxes on Income		327	327	275	(52)
25	Taxes Other Than on Income		65	65	56	(9)
26	Total Operating Expenses		$ 2,659	$ 2,659	$1,487	$ (1,172)
27	Return		685	685	577	(108)
28	Rate Base		$ 8,793	$ 8,792	$7,407	$ (1,386)
29	Rate of Return		7.79%	7.79%	7.79%	0.00%
30	Derivation of Base Margin					
31	O&M Expenses	(Line 21)	$ 1,413	$ 1,413	$303	$ (1,110)
32	Depreciation	(Line 22)	853	853	853	(0)
33	Taxes	(Line 23+24)	393	393	331	(62)
34	Return	(Line 26)	685	685	577	(108)
35	Revenue Requirement		3,344	3,344	2,064	(1,280)
36	Less: Misc. Revenues	(Line 2)	-	-	-	-
37	Base Margin	(Line 1)	$ 3,344	$ 3,344	$2,064	$ (1,280)

RESULTS OF OPERATION MODEL
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2016
GAS SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description		Update Testimony (2016$)	Settlement (2016$)	Adopted CPUC Total (2016$)	Difference (Adopted less Reques (2016$)
1	Base Margin		$ 320,180	$ 306,281	$ 303,048	$ (17,132)
2	Miscellaneous Revenues		4,008	4,207	4,206	198
3	Revenue Requirement		$ 324,188	$ 310,487	$ 307,253	$ (16,934)
	OPERATING & MAINTENANCE EXPENSES					
4	Distribution		25,198	23,996	23,996	(1,202)
5	Gas Transmission		4,631	4,663	4,663	32
6	PSEP		-	-	-	-
7	Generation		552	531	531	(21)
8	Nuclear Generation (SONGS)		-	-	-	-
9	Engineering		11,710	11,589	11,589	(121)
10	Procurement		110	110	110	-
11	Customer Services		32,143	31,462	31,462	(681)
12	Information Technology		28,380	27,743	27,743	(638)
13	Support Services		23,209	22,645	22,645	(564)
14	Administrative and General		85,016	74,512	74,366	(10,650)
15	Subtotal (2013$)		210,949	197,251	197,105	(13,844)
16	Shared Services Adjustments		(18,456)	(18,361)	(18,361)	95
17	Reassignments		(30,000)	(26,903)	(26,903)	3,097
18	FERC Transmission Costs					
19	Escalation		6,557	6,129	6,129	(429)
20	Uncollectibles (0.174%)		557	533	527	(30)
21	Franchise Fees (2.0727%)		6,636	6,348	6,281	(355)
22	Total O&M (2016$)		176,244	164,997	164,778	(11,466)
23	Depreciation & Amortization		57,681	57,079	57,079	(602)
24	Taxes on Income		19,601	19,059	18,045	(1,556)
25	Taxes Other Than on Income		14,981	14,599	14,537	(444)
26	Total Operating Expenses		$ 268,507	$ 255,735	$ 254,439	$ (14,068)
27	Return		55,681	54,753	52,814	(2,866)
28	Rate Base		714,773	702,858	677,976	(36,796)
29	Rate of Return		7.79%	7.79%	7.79%	0.00%
30	Derivation of Base Margin					
31	O&M Expenses	(Line 21)	$ 176,244	$ 164,997	$ 164,778	$ (11,466)
32	Depreciation	(Line 22)	57,681	57,079	57,079	(602)
33	Taxes	(Line 23+24)	34,581	33,658	32,582	(2,000)
34	Return	(Line 26)	55,681	54,753	52,814	(2,866)
35	Revenue Requirement		324,188	310,487	307,253	(16,934)
36	Less: Misc. Revenues	(Line 2)	4,008	4,207	4,206	198
37	Base Margin	(Line 1)	$ 320,180	$ 306,281	$ 303,048	$ (17,132)

(End of Appendix A)

APPENDIX B

Sempra 2016 GRC
Appendix B

Table of Contents

Section	Content
1	Summary of Rate Base Reductions
2	Southern California Gas - Rate Base Calculations
3	San Diego Gas & Electric / Gas - Rate Base Calculations
4	San Diego Gas & Electric / Electric - Rate Base Calculations
5	50% Bonus Depreciation for 2015 and 2016
6	Disallowance of SONGs O&M expense

Appendix B

Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 1

I. Summary of Calculations

Southern California Gas	NPV Costs**	Rate Base Reductions
	$ 81,102	$ **59,815**

See Section 2

San Diego Gas & Electric	2016 Present Rates	NPV Costs**	Percentage Ratio	Rate Base Reductions
Gas Revenue Requirement	$ 310,452	$ 17,942	17%	$ **13,103**
Electric Revenue Requirement	$ 1,479,399	$ 85,501	83%	$ **61,844**
SDG&E Total GRC Revenue Requirement	$ 1,789,851	$ 103,443	100%	$ **74,947**

See Section 3
See Section 4

**Reference: TURN's motion to enter late-submitted exhibit into the Evidentiary Record, Workpapers, Page 1.
NPV Costs to Ratepayers are the higher future taxes due to forgone depreciation deductions less Section 481a adjustments, discounted to present value.

II. Adjustments in the RO model

Reductions were made to the Rate Base in the RO model. The following were the changes made to the RO model:

1) Southern California Gas

a) File Name: rbSCGTotals.xlsb, Tab: "Summarization": Adjustment of ($59,815) was made to cell: F23

2) San Diego Gas & Electric

a) File Name: rbSDGETotals.xlsb, Tab: "SummaryTotalRB": Adjustment of ($74,947) was made to cell: F21
b) File Name: rbSDGETotals.xlsb, Tab: "SummaryElectric": Adjustment of ($61,844) was made to cell: F20
c) File Name: rbSDGETotals.xlsb, Tab: "SummaryGas": Adjustment of ($13,103) was made to cell: F21
d) File Name: rbSDGETotals.xlsb, Tab: "ElecDistRatebase": Adjustment of ($61,844) was made to cell: F20
e) File Name: sum.xlsb, Tab: "Input 2": Made adjustments of ($61,844) to Electric Rate Base and ($13,103) to Gas Rate Base to Row 40

III. Revenue Impacts

1) Our models (shown in pages 2-4 of these workpapers) ESTIMATE that the 2016 Revenue Requirement impact of these Rate Base Reductions are:
a) Southern California Gas: Reduction of $7.143M
b) San Diego Gas & Electric - Electric Revenue Requirement: Reduction of $7.435M
c) San Diego Gas & Electric - Gas Revenue Requirement: Reduction of $1.554M

2) The Results of Operations model calculated that the ACTUAL 2016 Revenue Requirement impact of these Rate Base Reductions are:
a) Southern California Gas: Reduction of $7.138M
b) San Diego Gas & Electric - Electric Revenue Requirement: Reduction of $7.569M
c) San Diego Gas & Electric - Gas Revenue Requirement: Reduction of $1.580M

3) The ESTIMATED revenue requirements are within a 2% margin of error from the ACTUAL revenue requirement. See table below.

	Actual Rev Req Calculated by RO model	Estimated Rev Req	% Diff
SDGE/Gas	$1,624	$1,554	4.3%
SDGE/Electric	$7,780	$7,435	4.4%
SCG	$7,447	$7,143	4.1%

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Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 2
Pg 1 of 2

Southern California Gas
(in $000s)

Total Revenue Requirement Impact 2015-2042 (Nominal $):	**(156,243)**
Net Present Value of Revenue Requirement Impact (2016 $):	**(81,102)**

Total Rate Base Reduction	**$ 59,815**
Wt Cost of Capital (Rate of Return on RB)	8.02%
Income Tax Gross up	1.68765
FF&U NTG	1.01737
NTG Multiplier (adjusting for Taxes & FFU)	1.71697
Federal & State Tax Rate	40.746%
Uncollectible Rate	0.298%
Franchise Fee Rate	1.414%

	Capital Ratio	Cost	Weighted	Gross Up for Taxes & FFU	
Long Term Debt	45.60%	5.77%	2.63%	2.68%	
Preferred Stock	2.40%	6.00%	0.14%	0.25%	
Common Equity	52.00%	10.10%	5.25%	9.02%	
Total	100.00%		-8.03%	**11.94%**	a

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate Base	b	(59,815)	(57,514)	(55,214)	(52,913)	(50,613)	(48,312)	(46,012)	(43,711)	(41,410)	(39,110)	(36,809)	(34,509)
Depreciation	c		(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)
Revenue Requirement Calculations (Bottoms Up)													
Return on Ratebase, after Gross Up	a*b	(7,143)	(6,868)	(6,593)	(6,319)	(6,044)	(5,769)	(5,494)	(5,220)	(4,945)	(4,670)	(4,396)	(4,121)
Depreciation Expense	c		(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)
Revenue Requirement (Nominal)	(a*b)+c	**(7,143)**	**(9,169)**	**(8,894)**	**(8,619)**	**(8,345)**	**(8,070)**	**(7,795)**	**(7,520)**	**(7,246)**	**(6,971)**	**(6,696)**	**(6,421)**
Net Present Value Calculations*													
Rev Req in 2016$		**(7,143)**	**(8,488)**	**(7,622)**	**(6,838)**	**(6,129)**	**(5,487)**	**(4,907)**	**(4,382)**	**(3,909)**	**(3,481)**	**(3,096)**	**(2,748)**
Net Present Value		**(81,102)**											

* Discount Rate used is the Cost of Capital, 8.02%.

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Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 2 of 4
Pg 2 of 2

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
(32,208)	(29,907)	(27,607)	(25,306)	(23,006)	(20,705)	(18,405)	(16,104)	(13,803)	(11,503)	(9,202)	(6,902)	(4,601)	(2,301)	(0)	-
(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	**(59,815)**
(3,846)	(3,571)	(3,297)	(3,022)	(2,747)	(2,473)	(2,198)	(1,923)	(1,648)	(1,374)	(1,099)	(824)	(549)	(275)	(0)	(96,428)
(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(2,301)	(59,815)
(6,147)	**(5,872)**	**(5,597)**	**(5,323)**	**(5,048)**	**(4,773)**	**(4,498)**	**(4,224)**	**(3,949)**	**(3,674)**	**(3,399)**	**(3,125)**	**(2,850)**	**(2,575)**	**(2,301)**	**(156,243)**
(2,436)	**(2,154)**	**(1,901)**	**(1,673)**	**(1,469)**	**(1,286)**	**(1,122)**	**(975)**	**(844)**	**(727)**	**(623)**	**(530)**	**(447)**	**(374)**	**(310)**	**(81,102)**

Appendix B

Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 3
Page 1 of 2

San Diego Gas & Electric - Gas
(in $000s)

Total Revenue Requirement Impact 2015-2042 (Nominal $):	**(34,077)**
Net Present Value of Revenue Requirement Impact (2016 $):	**(17,942)**

Total Rate Base Reduction	**$ 13,103**
Wt Cost of Capital (Rate of Return on RB)	7.79%
Income Tax Gross up	1.68765
FF&U NTG - Gas	1.02295
NTG Multiplier (adjusting for Taxes & FFU) - Gas	1.72637
Federal & State Tax Rate	40.746%
Uncollectible Rate - Gas	0.174%
Franchise Fee Rate - Gas	2.073%

	Capital Ratio	Cost	Weighted	Gross Up for Taxes & FFU	
Long Term Debt	45.25%	5.00%	2.26%	2.31%	
Preferred Stock	2.75%	6.22%	0.17%	0.30%	
Common Equity	52.00%	10.30%	5.36%	9.25%	
Total	100.00%		7.79%	**11.86%**	a

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate Base	b	(13,103)	(12,599)	(12,095)	(11,591)	(11,088)	(10,584)	(10,080)	(9,576)	(9,072)	(8,568)	(8,064)	(7,560)
Depreciation	c		(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)
Revenue Requirement Calculations (Bottoms Up)													
Return on Ratebase, after Gross Up	a*b	(1,554)	(1,494)	(1,434)	(1,374)	(1,315)	(1,255)	(1,195)	(1,135)	(1,076)	(1,016)	(956)	(896)
Depreciation Expense	c		(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)
Revenue Requirement (Nominal)	(a*b)+c	**(1,554)**	**(1,998)**	**(1,938)**	**(1,878)**	**(1,819)**	**(1,759)**	**(1,699)**	**(1,639)**	**(1,580)**	**(1,520)**	**(1,460)**	**(1,400)**
Net Present Value Calculations*													
Rev Req in 2016$		**(1,553.56)**	**(1,853)**	**(1,668)**	**(1,500)**	**(1,347)**	**(1,209)**	**(1,083)**	**(970)**	**(867)**	**(774)**	**(690)**	**(614)**
Net Present Value		**(17,942)**											

* Discount Rate used is the Cost of Capital, 7.79%.

Appendix B

Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 3
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2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
(7,056)	(6,552)	(6,048)	(5,544)	(5,040)	(4,536)	(4,032)	(3,528)	(3,024)	(2,520)	(2,016)	(1,512)	(1,008)	(504)	-	-
(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	**(13,103)**
(837)	(777)	(717)	(657)	(598)	(538)	(478)	(418)	(359)	(299)	(239)	(179)	(120)	(60)	-	(20,973)
(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(504)	(13,103)
(1,341)	**(1,281)**	**(1,221)**	**(1,161)**	**(1,102)**	**(1,042)**	**(982)**	**(922)**	**(862)**	**(803)**	**(743)**	**(683)**	**(623)**	**(564)**	**(504)**	**(34,077)**
(545)	**(483)**	**(427)**	**(377)**	**(332)**	**(291)**	**(255)**	**(222)**	**(192)**	**(166)**	**(143)**	**(122)**	**(103)**	**(86)**	**(72)**	**(17,942)**

Appendix B

Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 4
Page 1 of 2

San Diego Gas & Electric - Electric
(in $000s)

Total Revenue Requirement Impact 2015-2042 (Nominal $):	**(162,219)**
Net Present Value of Revenue Requirement Impact (2016 $):	**(85,501)**

Total Rate Base Reduction	**$ 61,844**
Wt Cost of Capital (Rate of Return on RB)	7.79%
Income Tax Gross up	1.68765
FF&U NTG - Electric	1.03729
NTG Multiplier (adjusting for Taxes & FFU) - Electric	1.75059
Federal & State Tax Rate	40.746%
Uncollectible Rate - Electric	0.174%
Franchise Fee Rate - Electric	3.427%

	Capital Ratio	Cost	Weighted	Gross Up for Taxes & FFU	
Long Term Debt	45.25%	5.00%	2.26%	2.35%	
Preferred Stock	2.75%	6.22%	0.17%	0.30%	
Common Equity	52.00%	10.30%	5.36%	9.38%	
Total	100.00%		7.79%	**12.02%**	a

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Rate Base	b	(61,844)	(59,465)	(57,087)	(54,708)	(52,330)	(49,951)	(47,572)	(45,194)	(42,815)	(40,436)	(38,058)	(35,679)
Depreciation	c		(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)
Revenue Requirement Calculations (Bottoms Up)													
Return on Ratebase, after Gross Up	a*b	(7,435)	(7,149)	(6,863)	(6,577)	(6,291)	(6,005)	(5,719)	(5,433)	(5,147)	(4,861)	(4,575)	(4,290)
Depreciation Expense	c		(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)
Revenue Requirement (Nominal)	(a*b)+c	**(7,435)**	**(9,528)**	**(9,242)**	**(8,956)**	**(8,670)**	**(8,384)**	**(8,098)**	**(7,812)**	**(7,526)**	**(7,240)**	**(6,954)**	**(6,668)**
Net Present Value Calculations*													
Rev Req in 2016$		**(7,435)**	**(8,839)**	**(7,954)**	**(7,151)**	**(6,422)**	**(5,762)**	**(5,163)**	**(4,621)**	**(4,130)**	**(3,686)**	**(3,284)**	**(2,922)**
Net Present Value		**(85,501)**											

* Discount Rate used is the Cost of Capital, 7.79%.

Appendix B

Sempra 2016 GRC
Revenue Requirement Impact of Rate Base Reduction
Section 4
Page 2 of 2

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
(33,301)	(30,922)	(28,543)	(26,165)	(23,786)	(21,408)	(19,029)	(16,650)	(14,272)	(11,893)	(9,514)	(7,136)	(4,757)	(2,379)	(0)	-
(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	**(61,844)**
(4,004)	(3,718)	(3,432)	(3,146)	(2,860)	(2,574)	(2,288)	(2,002)	(1,716)	(1,430)	(1,144)	(858)	(572)	(286)	(0)	(100,375)
(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(2,379)	(61,844)
(6,382)	**(6,096)**	**(5,810)**	**(5,524)**	**(5,238)**	**(4,952)**	**(4,666)**	**(4,380)**	**(4,094)**	**(3,808)**	**(3,522)**	**(3,237)**	**(2,951)**	**(2,665)**	**(2,379)**	**(162,219)**
(2,594)	**(2,299)**	**(2,033)**	**(1,793)**	**(1,677)**	**(1,383)**	**(1,209)**	**(1,053)**	**(913)**	**(788)**	**(676)**	**(576)**	**(488)**	**(408)**	**(338)**	**(85,501)**

Sempra 2016 GRC
Bonus Depreciation of 50% for 2015 and 2016
Section 5

I. Context

The Results of Operation model was adjusted to reflect 50% bonus depreciation for 2015 and 2016.
The 50% Bonus Depreciation was extended by the Protecting Americans from Tax Hikes Act (Path Act) in December 2015.

II. Adjustments in the RO model

To reflect the 50% bonus depreciation for 2015 and 2016, the following adjustments were made to the Results of Operations model.

1) Southern California Gas

a) File Name: taxSCGDeferred.xlsb, Tab: "2016RMFedDeprOnAdds": Adjustment of 50% was made to "Bonus Depreciation"
b) File Name: taxSCGDeferred.xlsb, Tab: "2015RMFedDeprOnAdds": Adjustment of 50% was made to "Bonus Depreciation"
c) File Name: taxSCGDeferred.xlsb, Tab: "2016RMFedDeprOnAddsShrdSvcs": Adjustment of 50% was made to "Bonus Depreciation"
d) File Name: taxSCGDeferred.xlsb, Tab: "2015RMFedDeprOnAddsShrdSvcs": Adjustment of 50% was made to "Bonus Depreciation"

2) San Diego Gas & Electric

a) File Name: taxSDGEDeferred.xlsb, Tab: "2016RMFedDeprOnAdds": Adjustment of 50% was made to "Bonus Depreciation"
b) File Name: taxSDGEDeferred.xlsb, Tab: "2015RMFedDeprOnAdds": Adjustment of 50% was made to "Bonus Depreciation"
c) File Name: taxSDGEDeferred.xlsb, Tab: "2016RMFedDeprOnAddsShrdSvcs": Adjustment of 50% was made to "Bonus Depreciation"
d) File Name: taxSDGEDeferred.xlsb, Tab: "2015RMFedDeprOnAddsShrdSvcs": Adjustment of 50% was made to "Bonus Depreciation"

III. Revenue Impacts

2016 Revenue Requirement impact of reflecting 50% Bonus Depreciation for 2015 and 2016 are:

a) Southern California Gas: Reduction of $12.784M in Revenue Requirement
b) San Diego Gas & Electric: Reduction of $9.390M in Revenue Requirement

Sempra 2016 GRC
Adjustment to SONGs O&M
Section 5

I. Context

In its Test Year 2016 GRC application, SDG&E requests $1.064 million for SONGS Unit 1 offsite spent fuel costs. The decision disallows recovery of these costs.

II. Adjustments in the RO model

San Diego Gas & Electric

a) File Name: RO.mdb, 2100-NSS, 1ES000-000 EG SONGS Wkp_Grp1: Adjustment of ($1,064) to NSE

APPENDIX C

GLOSSARY

Accumulated Deferred Income Tax	ADIT
administrative and general	A&G
Administrative Law Judges	ALJs
advanced metering infrastructure	AMI
American Taxpayer Relief Act of 2012	ATRA
authorized payment locations	APLs
billion cubic feet	Bcf
California Alternate Rates for Energy	CARE
California Corporation Franchise Tax	CCFT
California Independent System Operator	CAISO
Chief Executive Officer	CEO
Coalition of California Utility Employees	CCUE
Department of Defense and All Other Federal Executive Agencies	FEA
distributed generation	DG
Distribution Integrity Management Program	DIMP
Distribution Risk Evaluation and Monitoring System	DREAMS
diverse business enterprise	DBE
Division of Oil, Gas and Geothermal Resources	DOGGR
electric regional operations	ERO
Energy Resource Recovery Account	ERRA
Environmental Defense Fund	EDF
Federal Energy Regulatory Commission	FERC
Federal Executive Agencies	FEA
Fire Risk Management	FiRM
Franchise Tax Board	FTB
full time equivalents	FTEs
General Order	GO
general rate case	GRC
geographic information system	GIS
incentive compensation program	ICP
information technology	IT
Internal Revenue Code	IRC

Internal Revenue Service	IRS
leak detection and repair	LDAR
Master Insurance Program	MIP
megawatt	MW
million cubic feet per day	MMcfd
Modified Accelerated Cost Recovery System	MACRS
Mussey Grade Road Alliance	MGRA
New Environmental Regulatory Balancing Account	NERBA
Office of Ratepayer Advocates	ORA
operating and maintenance	O&M
Order Instituting Rulemaking	R. or Rulemaking
Pacific Gas and Electric Company	PG&E
Pension Balancing Account	PBA
Post-Retirement Benefits Other Than Pension Balancing Account	PBOPBA
percentage repair allowance	PRA
Pipeline and Hazardous Materials Safety Administration	PHMSA
post test year	PTY
Prehearing Conference	PHC
Protecting Americans From Tax Hikes Act of 2015	PATH
public participation hearing	PPH
Rate Case Plan	RCP
results of operation	RO
Risk Assessment Mitigation Phase	RAMP
Safety and Enforcement Division	SED
Safety Model Assessment Proceeding	S-MAP
San Diego Consumers' Action Network	SDCAN
San Diego Gas & Electric Company	SDG&E
San Onofre Nuclear Generating Station	SONGS
Sempra Energy	Sempra
Senate Bill	SB
Small Contractor Opportunity Realization Effort	SCORE
Storage Integrity Management Program	SIMP
Southern California Edison Company	SCE
Southern California Gas Company	SoCalGas

Southern California Generation Coalition	SCGC
Supervisory, Control & Data Acquisition	SCADA
System Average Interruption Duration Index	SAIDI
System Average Interruption Frequency Index	SAIFI
Tax Prevention Act of 2014	TIPA
test year	TY
The Utility Reform Network	TURN
Transmission Integrity Management Program	TIMP
Treasury Decision	TD
Utility Consumers' Action Network	UCAN
Utility Workers Union of America	UWUA

(End of Appendix C)