

Decision 19-09-051 September 26, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.

Application 17-10-007

And Related Matter.

Application 17-10-008

DECISION ADDRESSING THE TEST YEAR 2019 GENERAL RATE CASES OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

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Attachment D - 2019 GRC PTY Details	

**DECISION ADDRESSING THE TEST YEAR 2019 GENERAL RATE CASES
OF SAN DIEGO GAS & ELECTRIC COMPANY
AND SOUTHERN CALIFORNIA GAS COMPANY**

Summary

Today's decision addresses the test year (TY) 2019 general rate case (GRC) applications of San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas).¹

The decision adopts a TY2019 revenue requirement of \$1.990 billion for SDG&E's combined operations (\$1.590 billion for electric and \$0.400 billion for its gas operations)² which is \$212.504 million lower than the \$2.203 billion that SDG&E had requested in its update testimony.³ The adopted revenue requirement represents an increase of \$107.378 million or a 5.70 percent increase over the current revenue requirement for 2018.⁴ Based on a high-level estimate, it is anticipated that a typical residential inland electric customer⁵ will see a monthly bill increase of 0.70 percent or \$1.10⁶ while an average residential gas

¹ A Glossary of terms used in this decision is attached as Attachment A.

² Attachment B of this decision contains the Summary of Earnings which reflects the revenue requirements adopted for SoCalGas and SDG&E.

³ In Application (A.) 17-10-007, SDG&E had originally requested a combined gas and electric revenue requirement of \$2.199 billion representing an increase of \$218 million (an 11 percent increase) over the 2018 costs that consumers are paying.

⁴ Attachment C contains 2019 revenue requirement comparisons for SDG&E and SoCalGas showing the current rates and the rates to be adopted for 2019.

⁵ Using 500 kilowatts per hour (kWh) in a month.

⁶ The amount was derived using an estimated system average rate percentage change.

customer⁷ can expect to see a monthly bill increase of 13.7 percent or \$4.76 for gas services.

For SoCalGas, the decision adopts a TY2019 revenue requirement of \$2.770 billion which is \$166.109 million lower than the \$2.937 billion that SoCalGas had requested in its update testimony.⁸ The adopted revenue requirement represents an increase of \$314.356 million or a 12.80 percent increase over the current revenue requirement for 2018. Based on a high-level estimate, it is anticipated that an average residential customer⁹ can expect to see an average monthly bill increase of 9.1 percent or \$3.98.

The decision also adopts post-test year (PTY) revenue requirement adjustments for SDG&E of \$134.157 million for 2020 (a 6.74 percent increase) and \$102.493 million for 2021 (a 4.83 percent increase).¹⁰ For SoCalGas, the PTY revenue requirement adjustments are \$219.539 million for 2020 (a 7.92 percent increase) and \$149.551 million for 2021 (a 5.00 percent increase).

The adopted revenue requirement and PTY increases for SDG&E will provide the necessary funds to allow it to operate its electric and natural gas transmission and distribution system safely and reliably and to fulfill customer service functions at reasonable rates.

⁷ Using 25 therms per month.

⁸ In A.17-10-008, SoCalGas had originally requested a revenue requirement of \$2.99 billion representing an increase of \$480 million (a 19.1 percent increase) over the 2018 costs that consumers are paying.

⁹ Using 35 therms per month.

¹⁰ Attachment D contains details regarding SDG&E's and SoCalGas' PTYs.

For SoCalGas, the adopted revenue requirement and PTY increases will provide the necessary funds to allow it to operate its natural gas transmission, gas distribution, and gas storage systems safely and reliably and to fulfill customer service functions at reasonable rates.

The adopted revenue requirements and PTY adjustments for SDG&E and SoCalGas were arrived at after thorough analysis and review of the record which includes over 500 exhibits consisting of testimony, workpapers, and other exhibits from utility and intervenor witnesses. Over 20 days of evidentiary hearings were conducted between July and August of 2018 and 18 intervenors actively participated in the proceedings by submitting testimony, conducting cross examination during hearings, and filing motions and briefs.

A large part of the revenue requirement increases represent costs for incremental safety-related programs and activities that are being added to the GRC for the first time as a result of the Risk Assessment Mitigation Phase (RAMP). The Commission developed a risk-based framework and the RAMP phase requires SDG&E and SoCalGas to identify key safety risks and to propose programs to mitigate these risks. Many of these programs are being approved and the funding allows SDG&E and SoCalGas to perform increased mitigation efforts to mitigate key safety risks such as wildfires caused by SDG&E equipment, catastrophic damage from pipeline failures and third party dig-ins, employer, employee, contractor, and public safety, and other key risks identified in Applicants' RAMP report. Applicants are the first utilities to incorporate RAMP into their GRC filings and these costs are being included in Applicants' respective revenue requirements for the first time in TY2019.

In addition, costs for SoCalGas' Pipeline Safety Enhancement Plan consisting of 11 pressure test projects, 10 pipeline replacement projects, and

284 valve replacement projects are being included in SoCalGas' GRC application for the first time pursuant to Decision 16-08-003 and these costs are reflected in SoCalGas' revenue requirement for the first time in TY2019.¹¹

The decision requires SDG&E and SoCalGas to track officer salaries, bonuses, and benefits that are embedded with other costs in their respective Officer Compensation Memorandum Accounts (OCMA). The OCMA balances shall be trued-up in Applicants' respective year-end adjustment filings for 2019 and the amounts refunded to ratepayers. The above costs were not able to be removed without causing undue delay and prejudice to parties because the statutory change to Pub. Util. Code § 706 which no longer allowed recovery of such costs took effect on January 1, 2019 when evidentiary hearings had already been concluded and final briefs had been submitted.

Costs arising from the Aliso Canyon gas leak incident are not included in the GRCs and have been removed from historical information relied on by witnesses. The decision also incorporates 2019 impacts from the Tax Cuts and Jobs Act (TCJA) and directs SDG&E and SoCalGas to file separate Advice Letters with the Commission's Energy Division to begin the process of returning to ratepayers 2018 tax savings from the TCJA. 2018 revenue impacts are outside the scope of the TY2019 GRCs.

The decision also denies the Joint Motion for Adoption of Settlement Agreement between Applicants and Small Business Utility Advocates primarily because the proposed Settlement Agreement does not discuss the revenue impacts of the various commitments made in the proposed Settlement

Agreement and provides no assurance that funding for other needs will not be diverted to meet these commitments.

Finally, the decision denies Applicants' requests to include a third PTY (2022) in their respective GRC cycles. The decision finds that a determination as to whether a three-year or four-year GRC cycle should be adopted must be applied uniformly to all large investor owned utilities that are regulated by the Commission. In addition, the appropriate term for the GRC cycle is currently being considered in Rulemaking (R.) 13-11-006 and the decision defers any decision regarding this issue to R.13-11-006. If a decision adopting a four-year GRC cycle is made in R.13-11-006, SDG&E and SoCalGas are required to file a petition to modify this decision.

1. Procedural Background

On October 6, 2017, San Diego Gas & Electric Company (SDG&E) filed its General Rate Case (GRC) application requesting authority to establish its revenue requirement and to update base rates for its electric and natural gas services for the period from January 1, 2019 through December 31, 2022.

Southern California Gas Company (SoCalGas) also filed its GRC application on October 6, 2017 requesting authority to establish its revenue requirement and to update base rates for its natural gas service for the period from January 1, 2019 through December 31, 2022.

The proceedings were consolidated in the assigned Administrative Law Judge (ALJ) ruling dated November 8, 2017 pursuant to Rule 7.4 of the Rules of Practice and Procedure (Rules). Consolidation promotes efficiency, minimizes conflicts in schedule, and promotes a more timely resolution of the two related applications.

Protests and Responses to the applications were filed by the following:

Protests:

- a. Consumer Federation of California (CFC) on November 15, 2017;¹²
- b. Southern California Generation Coalition (SCGC) on November 16, 2017;
- c. Shell Energy North America (US) L.P. (Shell Energy), Office of Ratepayer Advocates (ORA),¹³ Office of the Safety Advocate (OSA), Indicated Shippers (IS), City of Long Beach Gas & Oil Department (Long Beach), The Utility Reform Network (TURN), and Direct Access Customer Coalition (DACC), all on November 17, 2017;
- d. The National Diversity Coalition (NDC) on November 20, 2017; and
- e. Jason Zeller on November 22, 2017.

Responses:

- a. Southern California Edison Company (SCE) on October 19, 2017;
- b. Pacific Gas and Electric Company (PG&E) on October 27, 2017; and
- c. Environmental Defense Fund (EDF), and Coalition of California Utility Employees (CUE) on November 17, 2017.

¹² CFC filed a notice of name change on March 27, 2018 changing its name from Consumer Federation of California to Consumer Federation of California Foundation.

¹³ SB 854 (Stats. 2018, ch. 51) amended Pub. Util. Code § 309.5(a) such that ORA is now named the Public Advocate's Office of the Public Utilities Commission. However, because a majority of the pleadings and exhibits filed or received into evidence were filed under the name ORA or refer to this party as ORA, this decision shall refer to this entity as ORA.

Motions for party status were filed by the following entities and party status was granted as follows:

- a. Center for Accessible Technology (CforAT) on October 20, 2017 – motion was granted on October 30, 2017;
- b. Utility Consumers Action Network (UCAN) on December 5, 2017 – motion was granted on December 18, 2017;
- c. Union of Concerned Scientists (UCS) on December 15, 2017 – motion was granted on December 20, 2017;
- d. Sierra Club on December 18, 2017 – motion was granted on December 20, 2017;
- e. San Diego Consumers Action Network (SDCAN) and Small Business Utility Advocates (SBUA) both on January 5, 2018 – both motions were granted on January 8, 2018;
- f. Federal Executive Agencies (FEA) on January 8, 2018 – motion was granted on January 9, 2018;
- g. Agricultural Energy Consumers Association (AECA) on January 26, 2018 – motion was granted on February 2, 2018; and
- h. Protect Our Communities Foundation (POC) on May 1, 2018¹⁴ – motion was granted on May 17, 2018.
- i. California State University (CSU) on June 25, 2018 – motion was granted on July 5, 2018.
- j. City of Lancaster (Lancaster) on July 5, 2018 – motion was granted on July 9, 2018.
- k. A motion to intervene was filed by Tenaska Marketing Ventures on April 24, 2018 – motion was granted on April 27, 2018.

On November 22, 2017, a joint motion for protective order was filed by SDG&E and SoCalGas (collectively, Applicants) to facilitate discovery and

¹⁴ Applicants filed a Response on May 4, 2018 opposing POC's motion and POC filed a Reply to the Response on May 9, 2018.

exchange of confidential materials. No protests to the joint motion were filed and subsequently, the joint motion was granted on December 13, 2017.

On November 27, 2017, Applicants filed a joint reply to the protests and responses.

A Prehearing Conference (PHC) was held on January 10, 2018. At the PHC, the issues, procedural schedule and other procedural matters relating to the proceedings were discussed. Applicants were also required to serve supplemental testimony concerning the impact of proposed increases in rates on disconnections due to non-payment and supplemental testimony on tax issues.

On January 29, 2018, the assigned Commissioner issued a Scoping Memorandum and Ruling (Scoping Memo) setting forth the scope of issues and procedural schedule. An ALJ ruling was issued on February 5, 2018 clarifying the procedural schedule set forth in the Scoping Memo.

On January 31, 2018 EDF and SCGC filed respective position briefs and comments on the issue of Lost and Unaccounted for Gas (LUAF). Reply comments on LUAF were filed by TURN on February 8, 2018, and EDF on February 9, 2018. Joint reply comments were filed by Sierra Club and UCS, and SDG&E and SoCalGas on February 9, 2018. On March 8, 2018, the assigned Commissioner issued a ruling denying EDF's request to include LUAF in the scope of the proceedings.¹⁵

On March 9, 2018, Applicants filed a motion to amend the Scoping Memo requesting that the portion in sub-issue "f" concerning whether changes are

¹⁵ The ruling also stated that LUAF should instead be raised in R.15-01-008 and SoCalGas' Triennial Cost Allocation Proceeding.

needed to the reconnection process for gas customers be removed from the scope of the GRC. Responses opposing Applicants' motion were filed by CUE and TURN on March 26, 2018. Applicants filed a Reply on April 5, 2018. The assigned Commissioner amended the Scoping Memo on April 30, 2018, granting Applicants' motion and adding another sub-issue on whether Applicants have sufficient resources to implement their reconnection process.

On March 27, 2018, SDG&E and SoCalGas filed a joint motion for authority for each of them to establish a GRC memorandum account. Applicants' joint motion was granted by the ALJ ruling on June 7, 2018.

On April 20, 2018, the assigned ALJ issued a ruling establishing public participation hearings (PPH) in three different locations for SDG&E and six locations for SoCalGas. PPHs for SDG&E were held on June 13, 26, and 28, 2018 and for SoCalGas on May 29, June 12, 14, 19, 20, and 21, 2018.

On April 24, 2018, SCGC filed a motion to compel discovery and a motion to shorten the response time to its motion to compel discovery. Responses to SCGC's motion were filed by Applicants and EDF on May 1, 2018. SCGC filed a Reply to Applicants' Response on May 4, 2018. SCGC's motion to compel discovery was denied in the ALJ ruling on June 18, 2018.

On May 7, 2018, SDG&E filed a motion for leave to serve supplemental testimony of David Geier and William Speer. The motion was granted by the ALJ ruling on May 25, 2018.

On May 9, 2018, POC filed a motion for official notice of certain facts contained in a Form 10-K filing by SDG&E and a Form 10-Q filing by Calpine Corporation with the Securities and Exchange Commission. POC's motion for official notice was granted by the ALJ ruling on June 20, 2018.

On May 14, 2018, POC filed leave to submit supplemental testimony. SDG&E filed a Response on May 29, 2018 opposing POC's motion. POC's motion was granted in the ALJ ruling on June 4, 2018.

On May 29, 2018, SDG&E filed a motion to strike the direct testimony of POC. The motion to strike was denied by the ALJ ruling on June 6, 2018.

On June 18, 2018, Applicants filed a joint motion for official notice of related proceedings and for clarification that certain issues raised by EDF and SCGC are outside the scope of the proceedings. Responses to Applicants joint motion were filed by SCGC on June 27, 2018 and EDF on June 28, 2018. A ruling was made by the assigned ALJ during the evidentiary hearing on July 10, 2018 granting the motion for official notice of related proceedings. The ruling also clarified that all core balancing issues and storage issues regarding Aliso Canyon are outside the scope of the GRC.¹⁶ On September 17, 2018, the assigned ALJ issued a follow-up ruling resolving a remaining issue in the joint motion and ruled that EDF's requests regarding improvements to backbone transmission and storage services are outside the scope of the GRC proceedings.

Evidentiary hearings were held from July 9, 2018 to August 8, 2018, and on August 28, 2018. Corrections to the hearing transcripts were adopted by the ALJ ruling on September 20, 2018.

Pursuant to the Commission's Rate Case Plan, SDG&E and SoCalGas served Update Testimony on August 24, 2018.

¹⁶ Transcript Volume 11 at 579 to 580.

On August 13, 2018, SDG&E and SoCalGas filed a brief regarding their evidentiary objections to Exhibit 475.¹⁷ Sierra Club and UCS filed their opposition brief regarding Exhibit 475 on August 21, 2018. During the August 28, 2018 hearing, a ruling was made striking portions of Exhibit 475.¹⁸

On August 30, 2018, Sierra Club and UCS filed a motion for reconsideration of the ALJ ruling regarding Exhibit 475. Applicants filed a Response on September 7, 2018 and Sierra Club and UCS filed a Reply to applicants' response on September 14, 2018. The motion for reconsideration was denied by the ALJ ruling on October 3, 2018.

On September 17, 2018, the assigned ALJ issued a ruling admitting the update exhibits and joint comparison exhibits into the record.

Opening Briefs were filed by the following parties on September 21, 2018: Sierra Club and UCS; CUE; NDC; ORA; SDCAN; SCGC; TURN; Lancaster; SDG&E and SoCalGas; IS; UCAN; Long Beach; SBUA; OSA; FEA; CFC; EDF; and POC.

Reply Briefs were filed on October 12, 2018 by the following: SBUA; FEA; UCAN; CUE; NDC; ORA; TURN; Lancaster; POC; SDG&E and SoCalGas; OSA; Long Beach; Sierra Club and UCS; TURN; SCGC; and SDCAN.

¹⁷ Exhibit 475 was provisionally accepted into evidence on August 8, 2018 pending a ruling on the evidentiary objections of SDG&E and SoCalGas.

¹⁸ Motion to strike Exhibit 475 was granted to the following: Attachment 10; Attachment 13; page 2, lines 11 to 19 and lines 15 to 21; page 34, line 18 to page 35, line 1 including footnotes 167 to 169; page 36, line 16 to page 40, line 14 including footnotes 179 to 182; page 40, line 21 to page 41, line 1; and page 43, line 12 to page 44, line 18 including footnote 223. See transcript Volume 30 at 2765 to 2766.

On October 23, 2018, SDG&E and SoCalGas filed a Joint Motion to Strike Portions of OSA's Opening Brief. OSA filed a Response on November 7, 2018 and SDG&E and SoCalGas filed a Joint Reply to OSA's Response on November 19, 2018.

On March 5, 2019, SDG&E, SoCalGas, and SBUA filed a Joint Motion for Adoption of Settlement Agreement. The three parties also filed a separate motion on the same day for extension of time to file the joint motion for settlement agreement more than 30 days after close of evidentiary hearings. The motion for extension of time was granted by the ALJ Ruling on April 18, 2019.

The proceedings are deemed submitted on March 5, 2019 upon the filing of the Joint Motion for Adoption of Settlement Agreement between SDG&E, SoCalGas, and SBUA.

2. PPHs and Correspondence

A total of nine PPHs were held in different locations within the service territories of SDG&E and SoCalGas regarding their GRC applications.¹⁹ The PPHs were held in order to receive comments from the utilities' customers regarding the impact of the application on them.

Some of the PPH locations included Information Sessions where informational and educational materials were provided to members of the public immediately prior to a PPH. Members of the public were also given the opportunity to ask questions about basic information regarding the application and questions about the Commission from representatives of the Commission's Public Advisor's Office (PAO) and Energy Division as well as billing and service

¹⁹ PPHs were held in El Cajon, Escondido, and Chula Vista for SDG&E and in Visalia, Palmdale, Oxnard, Inglewood, Long Beach, and Riverside for SoCalGas.

questions from representatives of the utility. Parties that chose to be present such as the ORA were also given the opportunity to be present to answer questions regarding their participation in the proceeding.

Many speakers at the PPHs stated that they are on fixed incomes and cannot afford the proposed rate increase which they view to be a large increase from current rates. Some stated that they pay a lot for electricity and cannot even afford to run their air conditioner or heater. Some also stated that the different tiers are not working and that the utilities' shareholders should be responsible for the utilities' mistakes.

However, there were also speakers representing small business, local organizations, chamber of commerce organizations, first responders, and suppliers to the utilities that expressed support for reasonable rate increases necessary for capital investments and to improve infrastructure, maintain programs, and safety spending. Some speakers also expressed that SDG&E and SoCalGas work with local organizations to maintain affordable services.

In addition to comments at the PPHs, letters and emails were sent to the PAO concerning the two GRC applications.

Much of the correspondence received opposes the proposed rate increases. Ratepayers state that they are on fixed incomes or are unemployed or underemployed and would be adversely impacted and cannot afford further increases in their utility bills. Several customers that have fixed or limited incomes point out that the minimal increases to Social Security is not enough to keep pace or offset the large increases the utility has been asking for. These customers add that they also have to contend with inflation from other sources such as food, insurance, and medical expenses. Some comments state that the

proposed rate increases should be greatly reduced and that specifically, SDG&E's electric rates are among the highest in the country.

There were also comments stating that proposed rate increases are excessive and not justified because of the reduced costs of fuel and natural gas. Others pointed out that administrative costs, executive compensation, and the utilities' profits and revenues are too high and that the utilities should be responsible for the increased costs which resulted from their mistakes, mismanagement, and lack of financial planning.

Some comments specifically oppose the purchase of the Otay Mesa Energy Center and explain the purchase is unnecessary, discourages the formation of Community Choice Aggregation (CCA), and that the utilities should be moving away from relying on fossil fuels.

Some of the correspondences received from local organizations and institutions, chamber of commerce organizations, and businesses support the proposed rate increases and state that these are necessary for enhanced reliability and security including cyber security, upgrades to facilities and modernization of infrastructure, enhanced protections to the environment, greenhouse gas (GHG) reduction, funding of programs for outreach, education, research and development, and to aid to low income residents.

3. Background of the Applications

SDG&E and SoCalGas are subsidiaries of Sempra Energy (Sempra), a San Diego-based energy services holding company whose subsidiaries provide electricity, natural gas and value-added products and services in California.

SDG&E is a regulated public utility that provides electric and gas service to approximately 3.6 million people through 1.4 million electric meters and

873,000 natural gas meters. SDG&E's service territory spans 4,100 square miles in San Diego county and southern Orange county.

SoCalGas operates and maintains a natural gas distribution and transmission system and delivers energy to 21.8 million consumers through 5.9 million gas meters. SoCalGas' service territory encompasses approximately 24,000 square miles of diverse terrain throughout Central and Southern California, from Visalia to the Mexican border.

The two GRC applications seek to determine SDG&E's and SoCalGas' revenue requirement and base rates for Test Year (TY) 2019 and the post-test year (PTY) periods of 2020 and 2021. In addition, both utilities are requesting to add a third attrition year covering PTY2022, to their three-year rate case cycle. Rates are to be effective beginning January 1, 2019.

3.1. SDG&E's Application

SDG&E's GRC application seeks Commission authority to update its current revenue requirement and base rates to recover projected costs of using its electric and gas facilities, infrastructure, and other necessary functions, to provide safe and reliable electricity and natural gas services to its customers. SDG&E is also requesting the adoption of its proposed PTY mechanism for attrition years 2020, 2021, and 2022, and for approval of the regulatory balancing and memorandum accounts set forth in its testimony.

SDG&E is requesting a total of \$2.199 billion (\$1.766 billion for electric and \$433 million for natural gas) for costs to provide service in 2019. If approved, this would equate to an increase of \$218 million, or an 11 percent increase over 2018 costs that consumers are paying. A typical inland residential customer using 500 kWh in a month and 25 therms per month would expect to see a

monthly bill increase of around \$13.70 per month. The new rates are to be effective beginning January 1, 2019.

In addition to its request for 2019, SDG&E's requested cost increases for attrition years 2020, 2021, and 2022 are as follows: (a) for 2020, an additional \$151 million or a 6.9 percent increase from 2019 costs; (b) for 2021, an additional \$120 million or a 5.1 percent increase over 2020 costs; and (c) for 2022, an additional \$122 million or a 4.9 percent increase over 2021 costs.

Many parties to the proceeding reviewed SDG&E's application and recommend various adjustments to SDG&E's requests.

3.2. SoCalGas' Application

SoCalGas' GRC application requests that the Commission authorize SoCalGas' proposed adjustments to its current revenue requirement and base rates to recover projected costs for gas operations, facilities, infrastructure, and other functions necessary to provide utility services to its customers. SoCalGas also requests the adoption of its proposed PTY mechanism for attrition years 2020, 2021, and 2022, and approval of the regulatory balancing and memorandum accounts set forth in its testimony.

SoCalGas is requesting a total of \$2.99 billion for costs to provide service in 2019. If approved, this would result in an increase of \$480 million or 19.1 percent, over the authorized revenue requirement for 2018. An average residential customer not under the California Alternate Rates for Energy (CARE) program using 35 therms per month would expect to see a bill increase of around \$7.54 per month. The new rates are to be effective beginning January 1, 2019.

For attrition years 2020 to 2022, SoCalGas' requested increases are: \$237 million or 8.1 percent in 2020; \$193 million or 6.1 percent in 2021; and \$202 million or 6.0 percent in 2022.

Parties to the proceeding also reviewed SoCalGas' application and recommend various adjustments to SoCalGas' requests.

3.3. Shared Services

SDG&E and SoCalGas are related companies due to their corporate structure of being owned by the same parent company and because they are in the same business of providing utility services to customers. Thus, there are some services that are shared between these two utilities and with their corporate parent, Sempra.

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) the corporate center, 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 and the utility receiving the shared service will include the costs that were allocated and billed to it.

On the other hand, non-shared services are activities provided by functional areas at one utility that benefit only the utility performing the activity. These costs are not allocated and billed out to other entities. For non-shared services provided to the utility by the corporate center, the costs are treated as service costs consistent with how outside vendor costs are treated.

These topics are discussed more thoroughly in sections 29 and 35 of this decision where we discuss general administration functions of Sempra's Corporate Center, and shared services and shared assets billing of SDG&E and SoCalGas.

4. Analysis Overview

This section provides a general overview of how we analyzed the revenue requirement and other requests of SDG&E and SoCalGas, including requests relating to the utilities' Risk Assessment Mitigation Phase (RAMP).

The decision generally follows the topical analysis and discussion presented by parties in their briefs. The decision will examine each major topic, analyze and resolve all issues in each topic, and as applicable, determine the appropriate and reasonable funding amounts based on Applicants' requests and alternative proposals by various parties.

In each section, we describe the background of the particular costs that are being addressed and will then separately look into issues affecting SDG&E and SoCalGas. This is followed by a discussion of each utility's Operations and Maintenance (O&M) costs and Capital costs. The positions of various parties are summarized, followed by a discussion of each request and issues raised, including objections and counter-proposals by various parties.

We have reviewed all the exhibits in these proceedings pertaining to each section as well as the evidentiary hearing transcripts. We also reviewed the arguments made and positions raised by the parties in their briefs. We then considered, reviewed, and evaluated all the evidence and all the issues, positions, and arguments raised by parties as well as the state of the economy and the economic outlook described in the parties' exhibits and briefs in deciding what costs for TY2019 are reasonable and what should be adopted in each section of the decision.

Attachment B of this decision contains the adopted summary of earnings tables for SDG&E and SoCalGas, and contains the adjustments that we adopt to the revenue requirements of SDG&E and SoCalGas. The summary of earnings

table sets forth all of the components of the revenue requirement consisting of the total O&M costs, and the capital-related costs that are necessary to support Applicants' respective rate base. The summary of earnings tables shown in Attachment B reflects all of the costs or methodologies we have found to be reasonable as inputs into the Results of Operation (RO) model, which 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.

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.

4.1. RAMP Review

This GRC application is the first by a regulated utility to fully incorporate risk mitigation activities using the risk-informed framework developed by the Commission in the Safety Modeling Assessment Proceeding (S-MAP) and the Applicants' RAMP proceeding.²⁰ Applicants submitted testimony providing a roadmap of the RAMP risks that were incorporated into this GRC application.²¹ The testimony also provided context on viewing the funding requests through the lens of risk management. Testimony that incorporates RAMP-identified risks presents the proposed spending as a risk mitigation activity.

²⁰ The S-MAP proceeding addresses applications A.15-05-002 (SDG&E), A.15-05-003 (PG&E), A.15-05-004 (SoCalGas) and A.15-05-005 (SCE). The Commission opened Order Instituting Investigations (I.16-10-015 and I.16-10-016) to review the RAMP submission of SDG&E and SoCalGas.

²¹ Exhibit 5.

The SMAP, RAMP, and spending accountability process to integrate risk mitigation activities into the GRC began in 2014 and is still being refined. In April 2019, the Commission adopted 26 safety metrics for which utilities are to report their progress toward the risk mitigation goals set out in the GRCs.²² In addition, the recently closed and future SMAP proceedings have evaluated and will continue to evaluate the minimum elements to be used by large utilities for risk mitigation analysis in future RAMP and GRC applications. The Commission also approved improvements to Risk Mitigation Accountability and the Risk Spending Accountability reports, which will require additional internal tracking processes and tools to measure how well identified risks are actually being mitigated, and the risk reduced per dollar spent.

When they submitted this GRC in 2017, Applicants were the first utilities to incorporate RAMP into their GRC filings. The Commission's guidance was more limited at that time, and reporting was limited to safety-related activities that correspond to one or more of the Company's key safety risks scoring four or more in the Safety, Health and Environment category. As a result, Applicants selected activities from the RAMP Report that they thought should be further reviewed for inclusion in the GRC. Those activities were then assigned to GRC subject matter areas, and the risk mitigation activities were evaluated as part of determining specific requests in the GRCs. The specific RAMP-driven funding requests were then incorporated into witnesses' GRC forecasts.

In reviewing the RAMP-driven portions of witness testimony in this GRC, we find that many of the activities identified by Applicants as flowing from the

²² D.19-04-020.

RAMP and mitigating risk are activities that were already being performed by Applicants and were included in prior GRCs. Since Applicants designate both the risks and the mitigation activities as RAMP-related, and re-evaluated using a risk-based approach and framework, the general result is witness testimony that states that numerous activities are in fact mitigation of key risks, often leading to higher cost forecast. In fact, a considerable portion of the Applicants' requested increase in revenue requirement is comprised of RAMP-related requests.

We find that witness testimony that incorporates RAMP-driven requests identifies the total amounts associated with RAMP, but in many instances, provides little information about the activities themselves. Instead, RAMP-related activities are integrated with O&M and capital requests for each cost center.

Because the RAMP portion in Applicants' requests is not presented as separate and distinct from the non-RAMP portions, our review of funding requests for each cost center was informed by the Applicants' 2016 RAMP Report, but in many instances our decision is not based on risk mitigation but rather on standard GRC methods, such as the quality of the forecast, counterarguments by intervenors, and whether a given showing met the burden of proof.

We note that as set out in our April S-MAP and RAMP decision, the Sempra utilities will file their next RAMP on November 30, 2019 using the advanced S-MAP methodology with risk-spend efficiency scores. That RAMP filing will be incorporated into Applicants' next GRC filing on September 1, 2020,

for Test Year 2022. The first Risk Mitigation Accountability Report prepared by Applicants using these improved tools will be available in 2021.²³

Several parties expressed concern about relying on findings made during the RAMP process citing various weaknesses. We considered these issues in our review of RAMP-related requests and did not use findings made in the RAMP process as the sole reason for approving requests. We also find it more prudent to integrate RAMP into the GRC process now rather than wait until the process is completely developed. As stated above, the RAMP process continues to be refined and we expect that future RAMP integration in future GRC filings will provide better answers to the core questions of what spending is proposed to mitigate risks, and how has past spending reduced risk per dollar spent. Answers to those questions are not readily available to us here.

At this time, we also strongly encourage OSA to actively participate in SDG&E's and SoCalGas' next RAMP proceedings. We support and share OSA's goals to advocate for the improvement of Applicants' safety management and safety performance although we note that the majority of OSA's testimony in these proceedings focus on safety culture enhancements and practices and not revenue requirements. These issues are more appropriately raised and addressed in the Applicants' RAMP proceedings and we look forward to OSA's continued participation in future RAMP and GRC proceedings.

4.1.1. Enterprise Risk Management

Enterprise Risk Management (ERM) is the process of planning and organizing the activities of SoCalGas and SDG&E in order to minimize the effects

²³ *Id.* at 31.

of risk on capital and earnings. Applicants' ERM program facilitates the integration of risk into the review of enterprise risks with an emphasis on safety, prioritization of effective mitigation measures, and the investment decision-making process.

Applicants are requesting \$7.035 million in shared O&M costs for TY2019 which is \$2.462 million higher than 2016 recorded costs. Costs for the ERM program will fund activities of the vice-president group, the director of Operational Risk Management group, and the director of ERM & Compliance group. The above groups develop risk frameworks and implement risk management practices. Applicants explain that the increase in funding will be used to obtain support from industry experts and fund increased activities.

We reviewed Applicants' testimony and find the forecast of \$7.035 million for TY2019 reasonable and should be approved. The requested funding level will allow Applicants to support new activities and continued maturity of risk management practices. Parties do not oppose Applicants' ERM forecast.

4.2. Officer Compensation

Pursuant to Senate Bill (SB) 901, Public Utilities Code section 706 has been amended prohibiting certain investor owned utilities (IOUs) including SDG&E and SoCalGas, from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value (compensation and benefits), paid to an officer and requires that compensation instead be funded solely by shareholders.

The pertinent portion of the revised Section 706 reads as follows:

“(a) For purposes of this section, “compensation” means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation.

(b) An electrical corporation or gas corporation shall not recover expenses for compensation from ratepayers. Compensation shall be paid solely by shareholders of the electrical corporation or gas corporation.”

SB 901 was signed into law on September 21, 2018 and the revision to Section 706 became effective on January 1, 2019 or the first day of the TY2019 period for both SDG&E and SoCalGas. Pursuant to the above, the Commission issued Resolution E-4963²⁴ requiring SDG&E and SoCalGas (among other IOUs), to establish Officer Compensation Memorandum Accounts (OCMA) to track compensation paid to an officer pursuant to the revised Section 706. The OCMA was effective beginning January 1, 2019 until closed at the direction of the Commission.

Because the above events took place at a time when evidentiary hearings in these GRCs had already been concluded and all active parties had already filed opening and reply briefs in support of their final positions in the proceedings, we find that it would not be prudent and will cause unnecessary delay to the prejudice of all parties, ratepayers, the public, and the regulatory process, to require SDG&E and/or SoCalGas to revise their testimonies in order to extract the portions of costs that pertain to officer compensation and benefits as these costs are typically embedded in multiple costs and forecasts presented throughout the GRC. For example, costs centers containing officer compensation and benefits within the definition of the revised Section 706 such as a Chief Executive Officer (CEO), President, or Vice President (VP) will also include salaries and benefits of staff and other support personnel for that working group

²⁴ Resolution E-4963 was issued on December 13, 2018.

as well as non-labor costs. This would be true even for cost centers that are titled CEO or Vice President of a particular division, department, unit, or working group.

Thus, the approach taken by this decision with regards to officer compensation and benefits is to disallow funding for cost centers that are entirely made up of officer compensation and benefits. For cost centers that are only partially made up of such costs, the reasonableness of such costs are reviewed and authorized as a whole and inclusive of office compensation and benefits. However, SDG&E and SoCalGas shall comply with Resolution E-4963 and track these costs through their respective OCMA's. These amounts shall then be trued-up and refunded to ratepayers as part of SDG&E's and SoCalGas' respective year-end annual regulatory account balance update Advice Letter filings for 2019. SDG&E and SoCalGas shall include a list of the officer positions and the corresponding amounts for each position. This list will be granted confidential treatment and submitted under seal. In addition, the amounts tracked in the OCMA are to be taken into account by the post-test year (PTY) mechanisms that will be adopted in this decision to calculate SDG&E's and SoCalGas' respective revenue requirements for PTYs 2020 and 2021. These amounts are to be excluded from the revenue requirements in PTYs 2020 and 2021.

4.3. Aliso Canyon Costs and Returning Employees

Pursuant to Decision (D.)16-06-054, all additional costs that have stemmed from the Aliso Canyon gas leak incident that was first discovered on October 23,

2015 are excluded from this GRC²⁵ and have been removed from historical cost information. To help remediate the leak, SoCalGas temporarily reassigned certain employees and utility staff to perform various remediation functions. In this GRC cycle, these employees and utility staff are now returning to their regular assignments to perform their regular functions. As with most organizations, management must have the ability to redirect staff to perform emergency work and to address urgent issues and the Commission does not intend to micromanage utility operations to that extent as this is neither efficient nor necessary. Furthermore, the reassigned employees and utility staff were not permanently reassigned to perform Aliso Canyon gas leak duties and their regular duties and responsibilities did not go away. Therefore, this decision will address their regular duties and responsibilities moving forward. In addition, if any work had been deferred as a result of the temporary reassignment, such work must be performed within the labor costs that will be authorized in this decision and in addition to the regular work that the returning employees and utility staff regularly perform and no additional funds will be authorized to perform such deferred work.

5. Request to Adopt a Four-Year GRC Cycle

SDG&E and SoCalGas both request the inclusion of a 3rd attrition year or calendar year 2022 into their current three-year TY2019 GRC cycle. Applicants state that over the past several years, the GRC filing process has become much more complex and subject to extended delays both in the filing process and the timeframe for the issuance of a decision. Applicants cite to new processes and

²⁵ D.16-06-054 OP 12 at 332.

reviews such as the RAMP filings and new reporting requirements such as those that have been required in by the S-MAP. Applicants add that the process is projected to become even more complex as the minimum required elements for the RAMP filings is being further refined by the S-MAP as the process continues to evolve and a four-year GRC term would free up scarce resources to allow the Applicants to maintain their focus on safe and reliable operations and customer responsibilities.²⁶ A four-year GRC cycle will allow Applicants, intervenors, and the Commission more flexibility to manage the integrated S-MAP, RAMP, and GRC proceedings.

ORA strongly supports the request and states that a four-year GRC term allows for better utility financial and operational management of spending and investment.²⁷ On the other hand, CUE, IS, SCGC, SBUA, and TURN all recommend the continuation of the three-year cycle. These intervenors argue that a third attrition year does not add to or assure more time in processing S-MAP and RAMP requirements and creates a longer gap between the Commission's periodic review of Applicants' operations. Also, because the S-MAP and RAMP processes are both in their early stages, more frequent feedback from utilities and intervenors and review by the Commission may be required.

ORA, SDG&E and SoCalGas made a similar request in Applicants' TY2016 GRCs as part of a separate settlement agreement and filed a related petition for modification of D.14-12-025 in order to change the current three-year GRC cycle

²⁶ Exhibit 242 at JAM-3 and Exhibit 245 at KJD-2 to 3.

²⁷ Exhibit 426 at 16.

into a four-year cycle. The Commission denied the petition but directed the Commission's Energy Division to conduct a workshop to explore whether a four-year GRC cycle is more appropriate. A workshop was conducted on January 11, 2017 and a workshop report was issued by the Energy Division on March 8, 2018. Comments to the workshop report were filed by various parties in Rulemaking (R.)13-11-006 and the Commission expects to issue a decision on the matter.

In their requests to adopt a four-year GRC cycle, Applicants and ORA do not state or suggest that the reasons and circumstances cited in support of a four-year GRC cycle only apply to SDG&E and SoCalGas and not to the two other large utilities that file cyclical GRC applications with the Commission, namely, PG&E and SCE. Thus, absent any circumstances or events in a particular GRC cycle that specifically differentiates one or more of these large energy utilities mentioned, we find that a decision as to whether a three-year and four-year GRC cycle should be adopted should be applied uniformly to SDG&E, SoCalGas, PG&E and SCE. Moreover, the appropriate term for the GRC cycle is currently being considered in R.13-11-006 following the workshop and comment process in that proceeding and a decision in said proceeding would be uniformly applied, and rightfully so, to SDG&E, SoCalGas, PG&E and SCE.

Following the above reasoning, this decision does not resolve or make conclusions regarding the underlying and substantive reasons and arguments that either support or seek denial of Applicants' request and instead defers any decision regarding this issue to R.13-11-006.

We therefore deny Applicants' request in these proceedings to change their current three-year GRC cycle into a four-year cycle, and Applicants should seek substantive and procedural guidance in R.13-11-006. The GRC period

considered in this decision is TY2019 and attrition years 2020 to 2021. Proposals under various topics as well as testimony and other evidence made in these proceedings concerning 2022 are not discussed further in this decision. If a decision adopting a four-year GRC cycle is made in R.13-11-006, Applicants shall file a petition for modification of this decision.

6. Fueling Our Future

Fueling Our Future (FOF) is an enterprise wide initiative which is designed to provide an opportunity to examine how SDG&E and SoCalGas approach, organize, and execute work, with a focus and goal of achieving operational efficiency.²⁸ FOF focuses on innovating and modernizing process to meet the future needs of Applicants' business and strives to improve performance by better leveraging people, processes, and technology. Applicants state that FOF is part of an overall policy and culture of seeking continuous improvement where the company and its employees continue to seek new ways of doing business in order to increase efficiency of core operations and customer service.

The FOF project phase was commenced in 2016 and consisted of 18 weeks of structured work including identification, refinement, evaluation, and prioritization of ideas within each functional area. The project phase culminated in a final decision-making process to move forward and execute selected ideas. The FOF team members consisted of group leaders and associates, catalyst team members and associates, and core support team members, and team associates from the different functional units within SDG&E and SoCalGas. Sempra also

²⁸ Exhibit 222 at HDS/RC-1.

engaged the services of a third-party consulting firm, EHS Partners (EHS), which worked with teams to manage the process methodology, structuring analytics, and idea surfacing. EHS also provided the framework to help identify, evaluate, and prioritize initiatives. A total of 450 initiatives were selected for implementation from 2016 to 2019. These initiatives are currently in various stages ranging from completed projects to projects that are still being conceptualized.

Savings generated from FOF activities are passed to ratepayers in the form of reductions to the revenue requirement. Table HS/RC-1 and RC-2 in Exhibit 222²⁹ shows the impacted cost centers for SoCalGas and SDG&E respectively, and the corresponding reductions to the TY2019 forecast for each of these cost centers. Total savings for SoCalGas is \$42.760 million and for SDG&E \$26.231 million. Savings for each cost center were forecast using a zero-based method and were derived using input from subject matter experts.

6.1. Position of Intervenor

ORA reviewed Applicants' testimony, hundreds of pages of workpapers and conducted discovery. ORA had several issues with supporting documentation for several projects but in conclusion, does not oppose Applicants' forecast of FOF net benefits for TY2019.

TURN recommends that Applicants' estimated savings be passed on to ratepayers but also recommends that FOF Project Phase costs for the 18-week period in which structured FOF planning work was conducted be identified and deducted from 2016 base year revenues as these costs represent a one-time

²⁹ *Id.* at HDS/RC-8 to 9.

expense that will not be repeated as part of Applicants' ordinary course of business moving forward.

6.2. Discussion

We recognize Applicants' commitment to continue to seek increased operational efficiencies of core operations and customer service. With respect to the FOF forecast, we agree with both ORA and TURN that a few of the projects that ORA examined did not include proper support for the savings that were forecast.

However, in a data response to ORA, Applicants stated they are committed to realizing the FOF savings identified in direct testimony whether or not the savings are realized.³⁰ Thus, even if some projects are not implemented, the savings forecast for those projects have already been included in the GRC application and these savings will be deducted from requested budgets nonetheless. Some of the projects have also been completed and the savings from these can be readily identified. Therefore, we find that the forecast for FOF savings of \$42.760 million for SoCalGas and \$26.231 million for SDG&E should be authorized.

As stated previously, the savings in each cost category affected are being used as a reduction for the requested TY2019 budget for such cost category. These reductions from FOF are described in various testimonies in support of cost categories where they appear in. Because we are already approving these forecast savings in this section, we do not further discuss whether these savings calculations should be adopted when we discuss other sections that have a FOF

³⁰ Exhibit 399 at 4.

component. Instead, we simply apply the reductions that were already applied by SDG&E and SoCalGas to their TY2019 requests for those sections.

Regarding TURN's recommendation to deduct project costs incurred during the 18-week Project Phase, we agree with Applicants that these FOF activities fall within the umbrella of activities aimed at improving efficiencies and developing improvement programs. Therefore, we find these activities are not one-time and are continuous activities that are routinely being performed in the course of business. We also accept Applicants' explanation that routine work was not deferred and were re-assigned during the 18 weeks of the FOF Project Phase and that many of the employees that performed FOF-related work were exempt employees that continued to partly support their regular duties. In addition, we find that the savings generated from FOF activities offset labor costs that may have been incurred despite the re-assignment of regular work and partial work performed by exempt employees. Also, none of the costs paid to EHS were allocated to Applicants and were instead all retained by Sempra. Based on the foregoing, we find it reasonable to reject TURN's proposal to deduct any Project Phase costs, particularly labor costs for employees' participation.

7. Gas Distribution

This section examines the SDG&E and SoCalGas forecasts and requests relating to operating and maintaining their respective gas distribution systems and for constructing new gas distribution facilities needed to provide safe, clean, and reliable delivery of natural gas to their customers.

7.1. SoCalGas

SoCalGas' gas distribution system consists of a network of approximately 100,586 miles of interconnected gas mains, services, and associated pipeline

facilities.³¹ The primary function of this pipeline network is to deliver natural gas from SoCalGas' transmission system to approximately 5.9 million customer meters.

The TY2019 forecast for O&M costs is \$148.154 million which is \$31.522 million higher than 2016 adjusted, recorded expenses. For capital costs, SoCalGas is requesting \$278.473 million for 2017, \$324.801 million for 2018, and \$347.842 million for 2019.³² By comparison, recorded costs for 2016 were \$301.472 million. Key work categories to maintain system integrity include leak repairs; locating and marking of gas facilities to avoid third-party damage; leak surveys; system renewal; and operations, maintenance, and construction needs.

Part of the requested costs is driven by risk mitigation activities pursuant to the RAMP process. The table below summarizes key risks being mitigated and the estimated O&M and capital costs for the mitigation activities that are planned to be undertaken. These costs are embedded in the O&M and capital costs being requested by SoCalGas and the reasonableness of these costs are reviewed in the O&M and capital sections that they appear in.

³¹ Exhibit 07 at GOM-02.

³² Revised the forecast from \$278.473 million to \$284.802 million for 2017 and \$324.801 million to \$322.769 million for 2018 in the Update Testimony (Exhibit 514) at Attachment H.

RAMP Risk	2017	2018	2019
Catastrophic Damage Involving Third-Party Dig-Ins (O&M)	n/a	n/a	\$18,177,000
Employee, Contractor, Customer, and Public Safety (O&M)	n/a	n/a	\$9,826,000
Catastrophic Damage Involving High-Pressure Pipeline Failure (O&M)	n/a	n/a	\$59,000
Catastrophic Damage Involving Medium-Pressure Pipeline Failure (O&M)	n/a	n/a	\$33,945,000
RAMP-related O&M total	n/a	n/a	\$62,007,000
Catastrophic Damage Involving Third-Party Dig-Ins (capital)	\$3,800,000	\$2,500,000	\$0
Employee, Contractor, Customer, and Public Safety (capital)	\$3,871,000	\$3,304,000	\$2,204,000
Catastrophic Damage Involving High-Pressure Pipeline Failure (capital)	\$207,000	\$207,000	\$207,000
Catastrophic Damage Involving Medium-Pressure Pipeline Failure (capital)	\$6,196,000	\$7,487,000	\$8,271,000
RAMP-related capital total	\$14,074,000	\$13,498,000	\$10,682,000

Most of the RAMP activities were already being performed, but new and enhanced safety-related activities to mitigate risk have been included as a result of the RAMP process. O&M costs for incremental activities are \$11.526 million out of the \$62.007 million total O&M amount being requested for RAMP-related activities.

Catastrophic Damage Involving Third-Party Dig-Ins

According to SoCalGas, damages resulting from excavation activity represents the greatest safety threat to its pipeline infrastructure with potential catastrophic consequence to public safety.³³ Damage can range from minor

³³ Exhibit 07 at GOM-18.

scratches and dents to ruptures with uncontrolled release of natural gas. Mitigation activities include training, locating and marking, pipeline observation, and standardizing location equipment.

Employee, Contractor, Customer, and Public Safety

SoCalGas manages this risk through mitigation actions that have been implemented and developed over many years. New activities have been added pursuant to the RAMP process. Mitigation actions include employee training, personal protective and safety equipment, above and below-ground pipeline and facility inspections, confined space air monitoring system for field personnel, and upgrading coveralls and fresh air equipment.

Catastrophic Damage Involving High-Pressure Pipeline Failure

Activities to manage this risk include maintenance, training and qualification of pipeline personnel, application of corrosion control and cathodic protection, and emergency preparedness and odorization activities.

Catastrophic Damage Involving Medium-Pressure Pipeline Failure

SoCalGas manages mitigation of this risk by complying with applicable federal and state regulations.

The TY2019 forecasts incorporate \$4.742 million in O&M savings from FOF. Also, costs relating to the Aliso Canyon gas leak incident are excluded from the forecast and from historical costs.

7.1.1. Non-Shared O&M

The total forecast for non-shared O&M costs is \$147.879 million which is \$31.936 million higher than 2016 costs. SoCalGas' workforce consists of 1,900 distribution system employees which include front-line construction crews, technical planners, and field engineers. Non-shared O&M cost categories are composed of Field Operations & Maintenance, Asset Management, Operations

Management & Training, and Regional Public Affairs. The table below summarizes the costs for each cost category.

Non-shared O&M	2019	Change from 2016
Field Operations & Maintenance	\$129,116,000	\$30,449,000
Asset Management	\$6,965,000	-\$1,206,000
Operations and Management	\$7,378,000	\$1,733,000
Regional Public Affairs	\$4,420,000	\$960,000
Total	\$147,879,000	\$31,936,000

7.1.1.1. Field Operations & Maintenance

A majority of the O&M costs under this category relate to expenses to address the physical condition of SoCalGas' gas distribution system. Activities performed can be classified as preventive, corrective, or supportive. The following table provides a more detailed breakdown of the different cost centers comprising Field Operations & Maintenance.

Field Operations & Maintenance	2019	Change from 2016
Locate & Mark	\$16,050,000	\$2,422,000
Leak Survey	\$10,711,000	\$3,631,000
Measurement & Regulation	\$14,888,000	\$1,057,000
Cathodic Protection	\$18,322,000	\$3,919,000
Main Maintenance	\$20,772,000	\$9,389,000
Service Maintenance	\$16,997,000	\$6,658,000
Field Support	\$21,069,000	\$1,667,000
Tools, Fittings & Materials	\$10,307,000	\$1,706,000
Total	\$129,116,000	\$30,449,000

Locate & Mark

Owners of underground facilities are required by federal³⁴ and state³⁵ regulation to identify substructures at locations of planned excavations. Activities include locating and marking underground pipelines, conducting job observations, and performing pothole operations and depth check. A linear trend forecast was utilized to account for increased work anticipated in the TY. Increased costs are due to new federal, state, and local regulations and increase in construction activities.

Leak Survey

This cost category includes expenses associated with federal and state pipeline safety regulations requiring SoCalGas to survey its gas distribution system for leakage.³⁶ Pipelines are routinely surveyed at one, three, or five-year intervals depending on the pipe material involved, the operating pressure, existence of cathodic protection, and proximity to various population densities. Special leak surveys are performed as needed or on more frequent cycles. SoCalGas utilized a historical linear trend for its forecast as it projects increased leak survey requirements. Costs incurred are based on the amount of pipeline footage requiring leak survey and frequency of the surveys.

Measurement & Regulation

Includes costs for maintaining and operating regular stations, customer meters, and associated components. Activities are driven by pipeline safety and

³⁴ 49 CFR §192.

³⁵ Cal. Gov't Code §§ 4126, *et seq.*

³⁶ 49 CFR § 192.723 and Commission General Order 112-F.

other regulations. A five-year linear trend was utilized to develop the forecast as costs are expected to continue increasing due to pipeline growth and because the system continues to age.

Cathodic Protection

Cathodic protection reduces corrosion of pipes in the distribution system. Maintenance work is also conducted to replace magnesium anodes that are no longer able to provide the required protection level for pipelines. Once again, a linear trend was utilized as costs are expected to continue increasing due to regulatory requirements.

Main Maintenance

Activities under this cost category are to meet federal and state pipeline safety regulations and to extend the life of distribution main pipelines. Activities also include leak evaluations, leak repair, service alterations, and miscellaneous maintenance. Costs are once again expected to keep increasing and so a historical linear trend was utilized to develop the forecast.

Service Maintenance

Service maintenance activity consists of evaluation and repair of service leaks, service alterations, customer meter alterations and meter guard replacements, and miscellaneous service and customer meter maintenance. Costs were forecast using a linear trend because costs are expected to keep increasing.

Field Support

The Field Support group conducts a variety of support services to complete daily Gas Distribution O&M activities. This includes field supervision, clerical support, dispatch operations, materials support, and removal of

abandoned mains. A five-year historical average was used to develop the forecast.

Tools, Fittings, and Materials

This workgroup contains the purchase of small tools, small pipe fittings, pipeline materials, and miscellaneous installation materials used during construction and maintenance activities. Costs were forecast using a historical linear trend as costs are expected to keep increasing due to increased construction activities.

7.1.1.2. Asset Management

Asset Management is responsible for the evaluation of the condition of the distribution system which includes maintaining asset records, identification of corrective maintenance solutions, and coordinating with field personnel. Costs were forecast using a historical linear trend because the level of work supported such as maintenance work, general construction work, municipality work, and customer-generated activities, are generally expected to keep increasing.

7.1.1.3. Operations and Management

This workgroup includes Operations Leadership and Field Management activities. Operations Leadership is responsible for the organization's vision and direction and setting and ensuring that objectives are met while Field Management is responsible for overall management of the workforce dedicated to the Gas Distribution pipeline maintenance and installation activities. Costs were forecast using a five-year historical linear trend because of increased and new activities that are projected.

7.1.1.4. Regional Public Affairs

The primary focus of the Regional Public Affairs group is to support Field Operations by working with regional and local governments and municipal

districts on issues relating to permits, proposed regulations, franchises, and emergency preparedness and response. Regional Public Affairs also informs county and city officials as well as special districts regarding issues that impact customers and serves as the point of contact for construction activities, customer programs, service inquiries, etc. A five-year average plus incremental increases was utilized to arrive at the TY2019 forecast.

7.1.1.5. Positions of Intervenors

Comments to the O&M section were provided by ORA, TURN, CUE and CFC.

ORA recommends a total of \$118.037 million for non-shared O&M costs which is \$29.842 million lower than SoCalGas' requested amount of \$147.879 million. Generally, ORA does not oppose the underlying activities being funded and much of the difference between ORA's recommendation and SoCalGas' is due to ORA's proposal of utilizing a two-year average using 2016 and 2017 recorded costs as opposed to SoCalGas' forecast methodologies which were mostly based on a five-year linear trend. ORA proposes using a two-year average for Operations and Management and all the Field Operations & Maintenance sub-categories except for Main Maintenance, Field Support, and Tools, Fittings, and Materials. For these three sub-categories, ORA recommends using 2016 recorded costs for Main Maintenance and Field Support and a five-year average for Tools, Fitting, and Materials. ORA also recommends using 2016 recorded costs for Operations and Management. ORA does not dispute the forecasts for Asset Management and Regional Public Affairs.

TURN recommends a reduction of \$14.909 million from SoCalGas' forecast. TURN recommends a five-year average for Main Maintenance and supports ORA's recommendation of a two-year average for Service Maintenance.

TURN also objects to the incremental funding for leak backlogs stating that this could overlap with SoCalGas' request in Advice Letter 5211 pursuant to SB 1371.

CFC recommends a reduction of \$0.500 million for SoCalGas' forecast for Cathodic Protection.

CUE recommends an increase of \$13.159 million from SoCalGas' forecast. CUE recommends increases in Locate and Mark, Aldyl-A leak survey, meter set assembly maintenance, and standbys for observation on high-pressure pipelines. CUE also recommends that SoCalGas should eliminate its leak backlog by the end of this GRC cycle and to move to a three-year leak survey cycle.

7.1.1.6. Discussion

7.1.1.6.1. Field Operations & Maintenance Issues

This section will address the various issues relating to Field Operations & Maintenance and the eight sub-categories that comprise it. The common issue of the appropriate forecast methodology is addressed concurrently.

Forecast Methodology

SoCalGas generally utilized a historical linear trend to develop its forecasts except for Leak Survey and Field Support. SoCalGas' rationale for these cases is that costs have been increasing year after year and it expects this trend to continue. We examined Table 11-4 of Exhibit 406³⁷ which shows recorded costs from 2012 to 2016. From said table however, the year over year increase in costs is only present for Locate and Mark, Measurement & Regulation, and Cathodic Protection. For said categories, we find the application of a historical linear trend to develop the forecasts is reasonable and appropriate. For Main Maintenance;

³⁷ Exhibit 406 at 8.

Service Maintenance; and Tools, Fitting & Materials; costs are shown to fluctuate and so a linear trend does not appear to be appropriate. For Leak Survey, we find SoCalGas' forecast methodology of basing its forecast on the amount of pipeline footage requiring leak survey and frequency of leak surveys to be appropriate especially because the amount of pipeline requiring survey has increased. For Field Support, we find that recorded costs from 2015 to 2017 are more reflective of current costs as compared to the five-year average from 2012 to 2016.

Locate & Mark

As stated in our discussion above regarding forecast methodology, recorded data from 2012 to 2016 supports SoCalGas' assertion that costs have been increasing. Based on the evidence presented, we find it reasonable that Locate & Mark costs will continue to increase due to regulations and increase in construction activities. CUE recommends an additional \$0.915 million based on additional upward trend from SB 661, also known as the Dig Safe Act of 2016, which requires additional notification from excavators which in turn increases Locate & Mark activities. However, SoCalGas states that its forecast already takes into account additional work anticipated from SB 661. CUE also proposes an increase for Locate & Mark standby-time for job observation on high-pressure pipelines but an increased standby-time trend was also already incorporated in SoCalGas' forecast. Thus, we find that CUE's recommended increases are already embedded in SoCalGas' proposed costs and not necessary. Parties do not object to the incremental adjustments presented by SoCalGas for its base forecast and we find that the testimony supports these costs. Based on the above, we find that SoCalGas' proposed forecast of \$16.050 million for Locate & Mark should be approved.

Leak Survey

Historical costs for Leak Survey went up from \$6.704 million in 2013 to \$8.000 million in 2014 but decreased to \$7.172 million in 2015 and to \$7.080 million in 2016. ORA suggests that these recorded expenses show a steady declining trend. In this case, we find it appropriate to examine 2017 costs in order to determine whether the trend continued but find that costs in 2017 went up to \$7.955 million. Based on the above, we disagree with ORA that there is a declining trend. In addition, SoCalGas shows in Figure GOM-04 of Exhibit 10³⁸ that the footage for leak survey has generally increased which requires more leak survey activities. New meter set installations are also expected to grow which also increases the number of leak survey activities. Thus, we find SoCalGas' base forecast of \$8.320 million to be more reasonable.

With regards to incremental costs, ORA recommends \$0 funding for Bi-Annual High-Pressure Leak Survey while CUE recommends an additional \$99,000 for the Aldyl-A Survey and \$0.500 million to do a field comparison using leak detection technology from a company called Picarro. CUE also recommends moving to a three-year inspection cycle for all pipes not already subject to more frequent inspections.

We find the funding for the Bi-Annual High-Pressure Leak Survey to be necessary as the activity is required by GO 112-F and supports risk mitigation activities pursuant to reducing the RAMP risk of Catastrophic Damage Involving High-Pressure Pipeline Failure. SoCalGas does not oppose CUE's recommendation of additional funding for Aldyl-A Survey and admits that the

³⁸ Exhibit 10 at GOM-24.

number of miles used for the forecast was lower than the current actual data. Thus, we agree with CUE's proposed increase. Regarding CUE's request to move to a three-year inspection cycle and to require a field comparison using Picarro leak detection technology, we find that these requests are outside the scope of this GRC and are already being addressed in R.15-01-008, the Gas Leak Abatement OIR addressing the requirements imposed by SB 1371.

Based on the above, we find that \$99,000 should be added to SoCalGas' TY2019 forecast of \$10.711 million resulting in an amount of \$10.810 million that should be approved for Leak Survey.

Measurement & Regulation

As stated in our discussion on forecast methodology, historical data supports SoCalGas' assertion that costs have been increasing and we find it reasonable that costs will continue to increase for this category due to aging of infrastructure components requiring more maintenance and inspections as well as pipeline growth. We also agree with the incremental costs presented in SoCalGas' testimony and parties do not oppose these incremental costs. Therefore, we find that SoCalGas' proposed forecast of \$14.888 million should be approved.

Cathodic Protection

As stated in our discussion on forecast methodology, historical data also supports SoCalGas' position that costs have been increasing and we find it reasonable that costs will continue to increase for this category due to increasing regulatory requirements and increased risk mitigation activities. CFC recommended a \$0.500 million reduction but SoCalGas points out that CFC's

recommendation relies on data from the Department of Transportation for the gas distribution system and not specific data for cathodic protection.³⁹ Thus, we find SoCalGas' forecast to more reliable. We also agree with the incremental costs presented in SoCalGas' testimony and parties do not oppose these incremental costs. Therefore, we find that SoCalGas' proposed forecast for Cathodic Protection of \$18.322 million should be approved.

Main Maintenance

Costs for Main Maintenance ranged from \$9.773 million to \$16.103 million from 2012 to 2016 with increases and decreases in costs fluctuating from year to year. Thus, we disagree with SoCalGas that costs are continuing to increase based on recorded costs. SoCalGas states that costs associated with mitigation actions associated with RAMP are embedded in its based forecast of \$16.016 million but the testimony does not clearly identify these costs and discuss whether these RAMP activities are historical RAMP activities or whether incremental RAMP activities are included. In reviewing historical costs, we find that a three-year average from 2014 to 2016 is more reflective of projected costs and so we find it reasonable to authorize \$13.498 million as the base cost. TURN had recommended a five-year average, but we find that costs in 2013 are not reflective of more recent costs and so we find it more reasonable to consider costs from 2014 onwards.

SoCalGas separated the costs for leak repairs from its base forecast and we have no objection to the \$6.00 million being requested. SoCalGas presented sufficient testimony that explains that said amount is for the 7,670 main leaks

³⁹ Exhibit 10 at GOM-45

that are to be addressed in 2017 and 2018 which were not reflected in the PTYs of the TY2016 GRC. CUE recommends an additional \$10.905 million for leak repairs stating that the inventory of leak repairs is expected to grow. However, the cost for leak repairs is only for the backlog of 7,670 main leaks to be repaired in 2017 and 2018. Additional leaks are expected to be addressed in SB 1371 and should not be counted here.

Based on the above, we find it reasonable to authorize \$18.254 million for Main Maintenance after applying \$6 million in incremental costs and the reduction of \$1.244 million in FOF savings.

Service Maintenance

Costs for Service Maintenance ranged from \$7.514 million to \$11.613 million from 2012 to 2016 with increases and decreases in costs fluctuating from year to year. Similar to our rationale for Main Maintenance, we disagree with SoCalGas that costs are continuing to increase based on recorded costs. SoCalGas once again states that costs associated with mitigation actions associated with RAMP are embedded in its base forecast of \$12.334 million, but as we stated in the discussion for Main Maintenance, SoCalGas' testimony does not clearly identify these embedded costs and does not discuss whether these RAMP activities are historical RAMP activities or whether incremental RAMP activities are included. In our review of historical costs, we find that a three-year average from 2014 to 2016 is more reflective of projected costs and so we find it reasonable to authorize \$11.110 million as the base cost. TURN recommended a five-year average, but we find that costs in 2013 are not reflective of more recent costs and so we find it more reasonable to consider costs from 2014 onwards.

ORA objects to and recommends zero funding for the incremental costs requested for meter set assembly maintenance activities, meter guard activities,

and inaccessible meter set assembly disconnections. CUE recommends an additional \$0.170 million to the \$1.523 million requested for meter set assembly maintenance activities.

The meter set assembly maintenance and meter guard activities are pursuant to a focused inspection program to comply with atmosphere corrosion requirements and to perform a more thorough inspection of all aspects of meter set assemblies that also require more skilled meter readers. The requested incremental costs are to address work inventory that had developed in 2016 and 2017 as a result of the more thorough inspections. On the other hand, the requested cost for inaccessible meter set assembly disconnections are in support of the restoration of 709 inaccessible meters and are being undertaken to mitigate risks associated with safety and gas system integrity. Based on our review, we find the activities described above necessary and the amounts requested reasonable. We therefore find that the incremental funding requested for meter set assembly maintenance activities, meter guard activities, and inaccessible meter set assembly disconnections should be approved. With respect to CUE's recommendation for an additional \$0.170 million, SoCalGas states that it expects to be able to meet its projected volume of work for TY2019 within its requested funding level and so we find that the additional amount recommended by CUE is not necessary.

Based on the above, we find that \$15.773 million should be approved for Service Maintenance representing an alternative base forecast of \$11.110 million based on a three-year average and SoCalGas' requested incremental amount of \$4.663 million.

Field Support

Costs for Field Support ranged from \$20.791 million to \$21.545 million from 2012 to 2014. In 2015, costs dropped to \$19.916 million and then to \$19.402 million in 2016. Because of the apparent shift in costs, we find it useful in this case to consider costs in 2017 as it adds an additional year and a more current one for determining the proper trend for Field Support costs. Costs for 2017 were \$19.055 million. With this additional data, we find that a three-year average from 2015 to 2017 is more appropriate for determining base costs for TY2019. The decrease in costs beginning in 2015 appears to have been maintained in 2016 and 2017. SoCalGas argues that RAMP-related and other incremental activities are expected for the TY but we find that such incremental work should be reflected in incremental costs rather than in base costs which is derived from a historical average. Thus, we find it reasonable to authorize base costs for Field Support at \$19.458 million which is the three-year average from 2015 to 2017. This amount should be adjusted to \$19.947 million after applying incremental expenses of \$1.075 million and a reduction of \$0.586 million for FOF to which we have no objections to.

Tools, Fitting, and Materials

Historical costs have gone up and down from 2012 to 2016 and we find that a historical linear trend is not supported by historical data. SoCalGas argues that increased level of work is expected but we find that such increase in work, if true, should be reflected as an adjustment to the historical average that was used in this case. Thus, we find SoCalGas' forecast methodology to be inappropriate in this case. However, costs generally appear to have increased over the fluctuations between increases and decreases and we find that a three-year average from 2014 to 2016 is more reflective of current costs rather than ORA's

recommendation of a five-year average. Thus, for base costs, we find it reasonable to authorize \$8.728 million. This amount should be adjusted to \$9.614 million after applying additions for incremental work that we find are justified by the testimony. ORA objects to the incremental costs for meter guard activities but we find that this cost supports necessary funding for meter guard replacements.

7.1.1.6.2. Asset Management and Regional Public Affairs

SoCalGas utilized a historical linear trend for its forecast for Asset Management although historical costs as shown in Table 11-20 of Exhibit 406⁴⁰ shows that costs decreased in 2015 and 2016. However, the application of FOF savings results in a forecast that is lower than any of the recorded costs from 2012 to 2016 and so we have no objections to SoCalGas' resulting forecast.

For Regional Public Affairs, we agree with ORA that the forecast is comparable to historical spending as shown in Table 11-22 of Exhibit 406.⁴¹ Thus, we find that SoCalGas' forecast should be adopted.

Based on the above, we find it reasonable to adopt SoCalGas' forecasts of \$6.965 million and \$4.420 million respectively for Asset Management and Regional Public Affairs.

7.1.1.6.3. Operations and Management

Table 11-21 of Exhibit 406 shows the recorded costs from 2012 to 2016.⁴² Except for 2014, costs have generally been increasing by around \$0.500 million

⁴⁰ Exhibit 406 at 38.

⁴¹ *Id.* at 42.

⁴² *Id.* at 39.

each year. Thus, we find that SoCalGas' use of a historical linear trend for its base forecast is reasonable. The TY2019 forecast also accounts for projected increases in 2017 and 2018 that are not shown in Table 11-21.

ORA also objects to the incremental funding for six Full-Time Equivalents (FTEs) and \$0.112 million for resumption of employees previously re-assigned to support work related to the Aliso Canyon gas leak incident. The record shows that the six employees were hired in 2017 and ORA's argument is that these are already captured in the 2017 revenue requirement. We agree with SoCalGas that the 2017 revenue requirement is derived from the TY2016 revenue requirement plus the applicable PTY adjustment for inflation and increased costs and does not capture the additional six FTEs being requested that were not part of the TY2016 GRC. Thus, we find it proper for SoCalGas to request these incremental additions in this GRC. For the returning employees previously re-assigned, costs for these employees had been excluded when they were re-assigned and we find it appropriate to include the associated costs for these employees now that they are returning to their regular duties. However, as we explained in section 4 of this decision, if any work had been deferred as a result of the temporary reassignment, such work must be performed within the labor costs that will be authorized in this decision and in addition to the regular work that the returning employees and utility staff regularly perform and no additional funds shall be authorized to perform such deferred work.

Based on the above, we find it reasonable to adopt SoCalGas' forecast of \$7.378 million.

7.1.1.6.4. Summary of Non-Shared O&M Costs

To summarize the above discussion of non-shared O&M costs, SoCalGas' requested amounts for Asset Management (\$6.965 million), Operations and Management (\$7.378 million), and Regional Public Affairs (\$4.420 million) should be approved.

For Field Operations & Maintenance, the following amounts should be approved:

Locate & Mark: \$16.050 million
Leak Survey: \$10.810 million
Measurement & Regulation: \$14.888 million
Cathodic Protection: \$18.322 million
Main Maintenance: \$18.254 million
Service Maintenance: \$15.773 million
Field Support: \$19.947 million
Tools, Fittings, & Materials: \$9.614 million

7.1.2. Shared O&M

Shared O&M costs are comprised of expenses incurred for Operations Leadership & Support as the activities by this group benefits both SDG&E and SoCalGas. Costs for this workgroup relate to expenses incurred for Field Services Leadership & Operations Assessment which provides leadership and sets goals and direction for the Gas Distribution organization. The forecast for TY2019 is \$0.275 million which is \$0.414 million less than 2016 costs. A zero-based method was utilized to develop the forecast because certain historical costs are no longer applicable.

Parties do not object to SoCalGas' shared O&M forecast and we find it reasonable to approve the TY2019 forecast of \$0.275 million. We find the forecast

to be supported by the evidence. The zero-based⁴³ method to develop the forecast is appropriate because certain historical costs have been shifted to other cost centers.

7.1.3. Capital

As stated previously, SoCalGas capital forecasts are \$278.473 million for 2017, \$324.801 million for 2018, and \$347.842 million for 2019. The table below provides a breakdown of the requested capital costs.

⁴³ A zero-based method utilizes a forecasting method that determines the projected budget for operations based on necessity rather than on historical spending. Management starts from zero and determines all expenses that are necessary for operations. All expenses must be necessary in order to be included in the projected budget and no expenses are automatically added based on historical spending.

Capital	2017⁴⁴	2018	2019
New Business	\$36,632,000	\$45,313,000	\$50,393,000
Pressure Betterments	\$23,088,000	\$23,088,000	\$23,088,000
Supply Line Replacements	\$4,209,000	\$4,209,000	\$4,209,000
Main Replacements	\$33,711,000	\$33,711,000	\$33,711,000
Service Replacements	\$28,538,000	\$31,470,000	\$34,403,000
Main & Service Abandonments	\$9,256,000	\$10,522,000	\$11,787,000
Regulator Stations	\$8,636,000	\$14,636,000	\$19,436,000
Cathodic Protection Capital	\$6,320,000	\$8,434,000	\$9,511,000
Pipeline Relocations - Freeway	\$7,837,000	\$7,837,000	\$7,837,000
Pipeline Relocations - Franchise	\$17,894,000	\$17,894,000	\$17,894,000
Other Distribution Projects & Meter Guards	\$3,656,000	\$11,596,000	\$11,596,000
Measurement & Regulation Devices	\$22,266,000	\$29,547,000	\$37,037,000
Capital Tools	\$14,386,000	\$14,220,000	\$12,322,000
Field Capital Support	\$61,317,000	\$70,292,000	\$74,618,000
Remote Meter Reading	\$727,000	\$2,032,000 ⁴⁵	\$0
Total	\$278,473,000	\$324,801,000	\$347,842,000

7.1.3.1. New Business

New Business provides for changes and additions to the existing gas distribution system to connect new residential, commercial, and industrial customers. This includes installations of gas mains and services, meter set assemblies,⁴⁶ and the associated regulator stations to provide service to

⁴⁴ The following 2017 capital forecasts were revised to the following amounts in the Update Testimony (Exhibit 514) at Attachment H: New Business \$43.342 million, Supply Line Replacements \$1.833 million, Service Replacement \$35.205 million, Main & Service Abandonments \$9.312 million, Regulator Stations \$6.427 million; Cathodic Protection Capital \$8.264 million, Pipeline Relocations - Freeway \$1.402 million, Pipeline Relocations - Franchise \$13.200 million, Other Distribution Projects & Meter Guards \$5.704 million, Field Capital Support \$65.384 million, Remote Meter Reading \$1.278 million.

⁴⁵ Revised from \$2.032 million to \$0 million in the Update Testimony (Exhibit 514) at Attachment H.

⁴⁶ Exhibit 7 at GOM-99.

customers. Costs were forecast using the projected new meter sets multiplied by the cost per meter.

7.1.3.2. Pressure Betterments

Pressure Betterments are projects performed on a continuing basis to maintain system reliability and service for all customers as new load (from new customers) is added to the distribution system. A five-year historical average was used to develop the forecast.

7.1.3.3. Supply Line Replacements

Supply Line Replacements consists of expenditures to replace high-pressure distribution pipelines also known as supply lines. The distribution supply line consists of 3,700 miles of pipeline constructed between the early 1920s to the present and the condition of these supply lines is constantly assessed and evaluated to determine whether replacement, localized repair, or abandonment is necessary. SoCalGas utilized a five-year average to develop its forecast.

7.1.3.4. Main Replacements

Activities under Main Replacements include installation of new mains to replace existing ones, main replacements in advance of public infrastructure projects, and service line replacements, existing service line tie-overs and meter set rebuilds in connection with newly installed replacements mains.

Replacements are due to leakage and anticipated leakages, defects, corrosion, deterioration of pipes, and to meet cathodic protection mandates. SoCalGas forecasts continuing main replacements at the five-year historical average rate.

7.1.3.5. Service Replacements

Service Replacements are for routine replacement of isolated distribution service pipelines to maintain system reliability. The main drivers for Service Replacements are leakage and corrosion. Service Replacement costs associated

with main replacements are captured in the forecast for main replacements. The forecast was developed using a five-year historical average.

7.1.3.6. Main and Service Abandonments

Costs for this project are associated with the abandonment of distribution mains and services without installation of replacement pipeline. This primarily occurs when pipeline is no longer needed for current pipeline operations and is not expected to be needed in the future such as when a city or state requests the vacating and demolition of public property, when a customer cancels service due to a building demolition, when temporary service becomes inactive or is terminated, etc. A linear trend was utilized to develop the forecasts.

7.1.3.7. Regular Stations

Costs for this project are associated with the upgrade, relocation, and replacement of regulator stations due to design obsolescence, active corrosion, deteriorating vaults or equipment, exposure to flooding, hazardous traffic conditions, safety, etc. According to SoCalGas, due to the large number of regulator stations that are beyond their average life expectancy, SoCalGas is proposing an accelerated replacement rate at which it replaces regulator stations by adding an incremental replacement of 8 in 2018 and 18 in 2019 in addition to its base forecast. A base year forecast plus incremental costs was used to develop the forecasts.

7.1.3.8. Cathodic Protection

This project concerns the installation and replacement of cathodic protection on pipelines. Cathodic Protection is a method for mitigating external corrosion on steel pipelines. A five-year linear trend was utilized for the forecast.

7.1.3.9. Pipeline Relocations – Freeway

This project is for relocation and alteration of SoCalGas facilities in response to external requests and as specified by agreements with state and local agencies. A five-year average was utilized for the forecast.

7.1.3.10. Pipeline Relocations – Franchise

This project is for relocation and alteration of SoCalGas facilities in response to external requests and as specified by agreements with city and county agencies. A five-year average was utilized for the forecast.

7.1.3.11. Other Distribution Projects & Meter Guards

Other Distribution Projects cover construction projects not covered under franchise agreements, freeway work, or in other capital budget cost categories. These were forecast using a five-year average. Meanwhile, Meter Guards are routinely installed to protect meter set assemblies. Meter Guard costs were forecast using a zero-based methodology.

7.1.3.12. Measurements & Regulation Devices

This project involves meters, regulators, gas energy measurement systems, and electronic pressure monitors. The expenditures involved are associated with replacements, repair, purchase of materials, and supporting new customers. The project also ensures accurate measurement of gas consumption, providing service to new customers, complying with rules and regulations governing gas metering, and public safety. A zero-based forecast was utilized for meters and gas energy measurement systems while a base year method was applied to electronic pressure monitors. For regulators, the forecast was based on the average regulator prices multiplied by the new business and installation requirements.

7.1.3.13. Capital Tools

This project is for the replacement of existing tools that are damaged, broken, technologically outdated, or have outlived their useful lives. SoCalGas utilized a five-year historical linear trend to develop its forecasts.

7.1.3.14. Field Capital Support

This project provides funding for a broad range of activities such as project planning, local engineering, clerical support, field dispatch, field management and supervision, updating of mapping products, and off-production time for support personnel and field crews that install Gas Distribution capital assets. Costs were forecast based on the level of historical costs as a percentage of construction costs incurred. The resulting labor ratio based on a five-year average was calculated at 32.7 percent.

7.1.3.15. Remote Meter Reading

This project is for changing curb meters that are incompatible with Advanced Metering Infrastructure (AMI) technology. According to SoCalGas, there are 26,000 meters that are affected. A zero-based method was used to develop the forecasts.

7.1.3.16. Positions of Intervenors

ORA and CUE provided comments to SoCalGas' capital requests and TURN provided comments regarding clothing and gear provided during safety fairs and civic and community events.

ORA proposes using recorded costs for 2017 for all capital projects. The forecasts for Pressure Betterments, Main Replacements, and Measurement & Regulation Devices were not opposed other than the recommendation to utilize 2017 recorded costs instead of the 2017 forecasts.

ORA opposes the linear trend methodology used for Service Replacements, Main and Service Abandonments, Cathodic Protection, and

Capital Tools. ORA also opposes the five-year averages used for one component of New Business and Pipeline Relocations – Freeway and Franchise. ORA recommends a two-year average for Regulator Stations and opposes any incremental funding. ORA also opposes funding for Remote Meter Reading in 2018, arguing that this AMI-related project should have been concluded in 2017. Lastly, ORA recommends zero funding for meter guards.

CUE proposes an additional \$5.936 million for Supply Line Replacements in 2019 based on a replacement rate of 4.7 miles as opposed to SoCalGas' proposal of just under two miles. CUE also recommends that an additional 25 incremental regulator stations be replaced on top of the 18 incremental replacements proposed by SoCalGas. CUE's proposal adds \$13.800 million to SoCalGas' requested amounts.

TURN recommends the removal of clothing and gear provided during safety fairs and civic and community events from 2016 costs.

7.1.3.17. Discussion

ORA's Recommendation to Use 2017 Recorded Costs

ORA recommends using 2017 recorded costs instead of SoCalGas' 2017 forecasts for all the proposed capital projects for Gas Distribution. With respect to the use of 2017 recorded costs versus 2017 forecasts, the rate case plan requires that the GRC application use the most recent data available at the time the application is filed. In this case, the GRC application was filed in late 2017 and so the most recent data available at the time of preparing and filing the application is the base year or 2016 data.

As the application progresses, it is often the case that newer data becomes available such as 2017 recorded data in this instance. While we note that recorded costs for 2017 are more accurate and more recent than the 2017 forecasts

that are included in the application, we find that it is not feasible to constantly update data for the entire application. It is also not practical to update all data in the GRC because of the vast amounts of data included in the application.

As such, we find that selectively updating only certain data or in this case applying 2017 recorded costs in some instances but not in others may lead to inconsistent results. This is because not all data that was submitted with the application is being updated. For example, updating select data to 2017 recorded costs in one area which results in a lower value than the 2017 forecast would be inconsistent if another update in a different area would result in a higher value than the forecast but was not applied.

We do however recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and we exercise our discretion in doing so in appropriate cases. But for this GRC, based on the explanation above, we will generally not apply select updating of data if the sole reason for doing so is simply to update data without any explanation why the updated data should be applied. In this case, we find it more appropriate to apply the 2017 forecasts for all the capital projects.

Approved Forecasts

We reviewed all the proposed capital projects for Gas Distribution to determine the necessity and reasonableness of each project as well as the proposed costs. We reviewed the testimony presented, the accompanying workpapers that provide specific details for each project, pertinent sections of the RAMP report associated with the four risks being mitigated in this section, and arguments raised by parties in briefs.

Based on our analysis and review of each proposed project, we find the following capital projects: (a) Pressure Betterments; (b) Main Replacements;

(c) Measurement & Regulation Devices; (d) New Business (e) Supply Line Replacements; (f) Service Replacements; (g) Main and Service Abandonments; (h) Regulator Stations; (i) Cathodic Protection; (j) Pipeline Relocations - Freeway; (k) Pipeline Relocations - Franchise; and (l) Other Distribution Projects and Meter Guards to be necessary and also find the requested funding levels for the above projects to be reasonable.

With respect to the above projects, we find that SoCalGas provided sufficient evidence to support and justify these projects. The above-mentioned projects support system reliability of SoCalGas' gas distribution system, promote safety, and allow SoCalGas to provide adequate service to its customers. We also find the various forecast methodologies utilized to be reasonable and appropriate.

ORA opposes the five-year average for one component of New Business and argues that using base year costs is more reliable. New Business costs are composed of new business construction, advanced metering infrastructure, new business trench reimbursements and new business forfeitures. ORA takes no issue with the first three but recommends using base year costs for the Main & Stub component of new business forfeitures. New business forfeitures are credits that a new business customer reimburses to SoCalGas for the cost of unused or underutilized facilities constructed at their request. Figure II of Exhibit 406⁴⁷ shows the five-year credits received for Main & Stub forfeitures. The figure shows that credits for 2016 of \$4.912 million are more than double than in any other year and ORA does not provide sufficient testimony for the

⁴⁷ Exhibit 406 at 50.

sharp increase and why it expects this trend to continue. On the other hand, we find that a five-year average in this case better reflects costs over time and normalizes highs and lows of fluctuating costs. SoCalGas also states that forfeitures are impacted by housing and construction events over a 10-year period which supports a forecast that takes into consideration costs over a longer period. Based on the above, we find SoCalGas' forecasts for New Business to be more appropriate.

CUE proposes an additional \$5.936 million for Supply Line Replacements in 2019 based on a replacement rate of 4.7 miles as opposed to SoCalGas' proposal of just under two miles. However, the need for replacements are based a variety of factors and tend to vary from year to year and we find that a five-year average better reflects these fluctuations as a longer period of time accounts for year to year increases and decreases.

ORA opposes the linear trend methodology used in developing the forecast for Service Replacements but Figure GOM-19 in Exhibit 10⁴⁸ shows that costs have been increasing each year from 2012 to 2016. In addition, SoCalGas' forecasts include embedded RAMP-related mitigation activities which ORA's forecast does not take into account. Thus, we find it reasonable to approve SoCalGas' requested forecasts for Service Replacements. CUE proposes replacing an additional number of non-bare steel services that are over 67 years old by the end of 2019. However, SoCalGas argues that age is not the only consideration used for replacement. In any case, the linear trend forecasts means that the projected replacement rate will increase moving forward.

⁴⁸ Exhibit 10 at GOM-100.

Similarly, for Main and Service Abandonments, Figure GOM-20 and Figure GOM-21 of Exhibit 10⁴⁹ show that costs and the number of main and service abandonment orders have been increasing each year since 2012 which supports SoCalGas' forecast methodology as opposed to ORA's recommendation of utilizing a two-year average.

For Regulator Stations, SoCalGas applied a base year forecast for its base forecast and states that costs for 2017 were lower than 2016 because of delays. SoCalGas adds that planning and permitting have been completed and that it intends to undertake the delayed construction. Thus, we find that a base year forecast is reasonable and appropriate for 2017, 2018, and 2019 base costs as costs generally appear to be increasing as shown in Figure GOM-22 of Exhibit 10.⁵⁰ The base costs also include embedded costs for RAMP-related projects that aim to mitigate key risks identified in the RAMP Report. For the incremental funding in 2018 and 2019 to replace an additional 8 and 18 regulator stations, we find the request to be reasonable in light of SoCalGas' aging infrastructure. SoCalGas also clarifies that age alone is not the sole criteria used for replacement and that factors such as safety, integrity, and reliability concerns are considered. Regarding CUE's proposal for an additional replacement of 25 regulators, we find that this premature at this time. However, we agree with CUE that SoCalGas should develop some sort of ranking system for regulator replacements. SoCalGas should include this information in its next GRC and should use this ranking system as part of the basis for determining its proposed

⁴⁹ *Id.* at GOM-104 to 105.

⁵⁰ *Id.* at GOM-107.

regulator replacement rate in its next GRC. For this GRC however, we find that SoCalGas' proposed forecasts for Regulator Stations should be adopted.

ORA recommends a three-year average for Cathodic Protection arguing that there is no clear up or down cost trend. However, Figure GOM-24 of Exhibit 10⁵¹ shows that although costs decreased from 2014 to 2015, the general trend is an upward increase. In addition, SoCalGas' forecasts include embedded costs for RAMP-related activities. Thus, we find SoCalGas' forecast methodology to be more appropriate.

ORA also opposes the five-year averages used for both Freeway and Franchise Pipeline Relocations citing more recent trends but as explained by SoCalGas, work on these projects are driven by requests from and agreements with external sources such as state and local agencies and city and county agencies and so costs are driven more by timing and volume of such requests. To capture such fluctuations, we find that a longer period of historical data is more appropriate to develop the forecasts rather than ORA's recommended three-year average.

With respect to Meter Guards, ORA based its analysis on the assumption that the funding for Meter Guards represents incremental funding being requested on top of SoCalGas' base forecast. However, SoCalGas separated its forecasts for Other Distribution Capital Projects and Meter Guards and so the funding being requested for Meter Guards reflects base activities and not incremental or additional funding. We have no objections to the forecast

⁵¹ *Id.* at GOM-177.

methodologies utilized by SoCalGas and find that its requested amounts for this project should be approved.

Based on the above reasons, we find that SoCalGas' requested forecasts for the above-named projects should be approved.

Modified Forecasts

We find that the forecasts for: (a) Capital Tools, (b) Field Capital Support, and (c) Remote Meter Reading should be modified as discussed below.

ORA objects to the linear trend utilized for Capital Tools and recommends a two-year average from 2016 and 2017. ORA also objects to the incremental funding of \$2.500 million to standardize locate and mark tools in 2018. Figure GOM-29 in Exhibit 10 shows the costs for Capital Tools from 2012 to 2016 as well as SoCalGas' projected base and total costs for 2017 to 2019.⁵² While we agree that costs have risen from 2012 to 2016, the figure shows that costs rose sharply in 2016 but slightly declined in 2017. Based on the figure, we are not certain that costs will continue to rise at the pace that SoCalGas projects and find it more appropriate to authorize 2016 recorded costs of \$9.665 million as the base cost for 2017, 2018, and 2019. We agree with the incremental \$3.800 million for 2017 to standardize locate and mark tools but agree with ORA that the additional \$2.500 million for 2018 to continue standardizing locate and mark tools do not appear to be necessary. We also have no objections to the additional \$1.100 million in 2018 for confined space air monitoring or the need for the \$1.667 million for Nomex coveralls and fresh air upgrades but find that this amount should be moved from 2017 to 2018 because the project has been

⁵² Exhibit 10 at GOM-132.

delayed. The above changes result in authorization of \$13.465 million for 2017, \$12.432 million for 2018, and \$9.665 million for 2019.

For Field Capital Support, we agree with the forecast methodology of 32.7 percent of constructions costs. SoCalGas' calculation for total construction costs must be modified to take into account and reflect the total construction costs being authorized for Gas Distribution capital projects in this section.

For Remote Meter Reading, we agree with ORA that funding for AMI deployment concluded in 2017. SoCalGas states that because of a manufacturing issue, deployment of curb meter transmission units have been delayed but are scheduled to be completed in 2018. However, as ORA points out, funding for completing curb meter transmission unit replacements was previously granted to SoCalGas so a delay in deployment should not require additional funding. Thus, we find that SoCalGas' requested funding of \$0.727 million for 2017 should be granted. SoCalGas' request of \$2.032 million for 2018 was removed in SoCalGas' Update Testimony (Exhibit 514) at H-2.

Other Issues

TURN states that clothing and other gear containing the utility's name and logo (excluding uniforms and hard hats) should not be funded by ratepayers. For Gas Distribution, the amount in question for 2016 was \$44,966.⁵³ SoCalGas states that these items are sometimes provided to employees during safety fairs and safety celebrations and are not intended for promotional and image building purposes. SoCalGas adds that these items containing SoCalGas' name and logo are also used at safety fairs and other civic and community events so customers

⁵³ Exhibit 494 at 77 to 78.

and other members of the public can easily identify SoCalGas employees in case they have questions or concerns. These types of clothing and gear are also provided to Regional Public Affairs members so they can be easily identified and respond to inquiries during emergencies or operational incidents. Based on the foregoing, we find that the above items are being used for reasonable purposes in connection with safety-related and public events that provide benefits to ratepayers. We therefore deny TURN's proposal to remove \$44,966 for clothing and gear from 2016 costs.

7.2. SDG&E

SDG&E's gas distribution system consists of a network of approximately 14,148 miles of interconnected gas mains, services, and associated pipeline facilities.⁵⁴ The primary function of this pipeline network is to deliver natural gas from SDG&E's transmission system to approximately 878,100 customer meters covering an area of 1,400 miles.

The TY2019 forecast for O&M costs is \$29.553 million which is \$3.755 million higher than 2016 adjusted, recorded expenses. For capital costs, SDG&E requests \$50.666 million⁵⁵ for 2017, \$91.606 million for 2018, and \$110.993 million for 2019. By comparison, recorded costs for 2016 were \$61.557 million. The O&M forecasts incorporate a total of \$0.517 million in savings from FOF.

⁵⁴ Exhibit 11 at GOM-02.

⁵⁵ Revised from \$50.666 million to \$75.757 million in Update Testimony (Exhibit 514) at Attachment I.

Key work categories to maintain system integrity include leak repairs, locating and marking of gas facilities to avoid third-party damage, leak surveys, and system renewal, and high-pressure pipeline documentation.

Many of SDG&E's Gas Distribution cost centers have the same heading, primary functions, activities, and cost drivers as the corresponding cost centers described and discussed in the SoCalGas portion and so reference to the SoCalGas section describing the cost center functions and activities is made whenever appropriate.

As was the case with SoCalGas, part of the requested SDG&E costs are driven by risk mitigation activities pursuant to the RAMP process. The table below summarizes key risks being mitigated and the estimated O&M and capital costs for the mitigation activities that are planned to be undertaken. These costs are embedded in the O&M and capital costs requested by SDG&E and the reasonableness of these costs is reviewed in the O&M and capital sections that they appear in.

RAMP Risk	2017	2018	2019
Catastrophic Damage Involving Third-Party Dig-Ins (O&M)	n/a	n/a	\$3,102,000
Employee, Contractor, Customer, and Public Safety (O&M)	n/a	n/a	\$3,148,000
Catastrophic Damage Involving Medium-Pressure Pipeline Failure (O&M)	n/a	n/a	\$8,046,000
Workforce Planning	n/a	n/a	\$319,000
RAMP-related O&M total	n/a	n/a	\$14,615,000
Catastrophic Damage Involving Third-Party Dig-Ins (capital)	\$256,000	\$256,000	\$256,000
Employee, Contractor, Customer, and Public Safety (capital)	\$4,053,000	\$4,053,000	\$4,053,000
Catastrophic Damage Involving Medium-Pressure Pipeline Failure (capital)	\$9,728,000	\$47,157,000	\$67,212,000
RAMP-related capital total	\$14,037,000	\$51,466,000	\$71,521,000

Most of the RAMP activities were already being performed but new and enhanced safety-related activities to mitigate risk have been included as a result of the RAMP process. O&M costs for incremental activities are \$1.096 million out of the \$14.615 million total O&M amount requested for RAMP-related activities.

Catastrophic Damage Involving Third-Party Dig-Ins

See section 7.1. in the SoCalGas section.

Employee, Contractor, Customer, and Public Safety

See section 7.1. in the SoCalGas section.

Catastrophic Damage Involving Medium-Pressure Pipeline Failure

See section 7.1. in the SoCalGas section.

Workforce Planning

Workforce planning is the risk of loss of employees with deep knowledge and understanding in operations. This risk is being mitigated by training and knowledge transfer programs as well as compliance and inspection programs.

7.2.1. O&M

O&M costs for SDG&E are comprised only of non-shared costs and the total forecast is \$29.533 million, \$3.755 million higher than 2016 costs. According to SDG&E, the increase is driven by system expansion, infrastructure renewal, field technical skills and training, improved documentation and control of pipeline materials, and integration of new technology. The table below summarizes the costs for each cost category.

Non-shared O&M	2019	Change from 2016
Field Operations & Maintenance	\$22,854,000	\$2,734,000
Asset Management	\$2,169,000	\$450,000
Operations and Management	\$4,510,000	\$571,000
Total	\$29,533,000	\$3,755,000

Descriptions of Asset Management and Operations and Management mirror the discussion in section 7.1.1.2. and 7.1.1.3. in the SoCalGas portion of Gas Distribution. Costs were forecast using a base year plus adjustments methodology. Field Operations & Maintenance is discussed with more detail below.

7.2.1.1. Field Operations & Maintenance

Majority of the O&M costs under this category relate to expenses associated with the physical condition of SDG&E's gas distribution system. Activities performed can be classified as preventive, corrective, or supportive in nature. The following table provides a more detailed breakdown of the different cost centers comprising Field Operations & Maintenance.

Field Operations & Maintenance	2019	Change from 2016
Other Services	\$202,000	-\$160,000
Leak Survey	\$1,841,000	\$270,000
Locate & Mark	\$3,589,000	\$563,000
Main Maintenance	\$3,422,000	\$457,000
Service Maintenance	\$1,867,000	\$233,000
Tools, Fittings & Materials	\$1,010,000	\$87,000
Electric Support	\$425,000	\$8,000
Supervision & Training	\$3,993,000	\$473,000
Measurement & Regulation	\$4,216,000	\$343,000
Cathodic Protection	\$2,289,000	\$460,000
Total	\$22,854,000	\$2,734,000

Descriptions for the following: (a) Locate & Mark; (b) Leak Survey; (c) Main Maintenance; (d) Service Maintenance; (e) Tools, Fitting & Materials; (f) Measurement & Regulation; and (g) Cathodic Protection mirror those in the SoCalGas portion found in section 7.1.1.1. except for the forecast methodologies that were utilized. A linear trend was used for Locate & Mark, Main Maintenance, Service Maintenance, and Measurement & Regulation while base year plus adjustments was used for Leak Survey and Cathodic Protection. For Tools, Fittings & Materials, a five-year average was used.

Other services, Electric Support, and Supervision & Training are unique to SDG&E and are described below.

Other Services

Other Services consists of miscellaneous expenses associated with Gas Distribution field operations not captured in other major workgroups. Examples are leak investigations of customers' house lines, leak surveys of transmission mains, landscaping repair, etc. Costs were forecast using a five-year historical average.

Electric Support

This workgroup includes labor and non-labor expenses for traffic control and construction support services during inspections under the Corrective Maintenance Program and general construction activities. The Corrective Maintenance Program is for specific inspection cycles pursuant to GO 165. Costs were forecast using a three-year average because of changes in how traffic control expenses were charged beginning in 2014.

Supervision & Training

This cost center includes expenses for employee field skills training, field supervision, management, and miscellaneous expenses related to gas operations. Costs were forecast using the base year plus adjustments because of increased supervision and training operations not captured in historical costs.

7.2.1.2. Positions of Intervenors

ORA and CUE provided comments to SDG&E's O&M forecasts.

ORA objects to the linear trend forecast methodology utilized for Locate & Mark, Main Maintenance, and Measurement & Regulation. ORA also opposes the incremental addition for Field Supervision under Supervision & Training.

CUE recommends an increase of \$0.627 million for Leak Survey in connection with a proposal to require SDG&E to move to a three-year leak survey cycle for all pipes not subject to more frequent inspections, additional funding for Aldyl-A leak surveys, and a field comparison using Picarro leak detection technology. CUE also proposes an addition of \$0.260 million to SDG&E's request for Locate & Mark. Lastly, CUE recommends increases of \$1.715 million associated with increased Aldyl-A pipe replacements and \$0.177 million associated with increased steel pipe replacements.

7.2.1.3. Discussion

7.2.1.3.1. Field Operations & Maintenance Issues

This section addresses the various issues relating to Field Operations & Maintenance and the ten sub-categories that comprise it. Table 9-5 of Exhibit 404 shows recorded costs from 2012 to 2016.⁵⁶

Unopposed Forecasts

The forecasts for: (a) Other Services, (b) Service Maintenance, (c) Tools, Fittings & Materials, (d) Electric Support, and (e) Cathodic Protection were not opposed by parties.

We agree with the five-year average utilized for Other Services and Tools, Fittings & Materials as it captures highs and lows from 2012 to 2016. We also agree with the linear trend utilized for Service Replacements as costs have generally been increasing and are expected to continue increasing. For Electric Support, we find that a three-year average is appropriate because of changes in how traffic control expenses were charged beginning in 2014, which were not captured in 2012 and 2013. For Cathodic Protection, we find a base year plus adjustments are reflective of current costs because of additional maintenance work and expansion of the GIS system that are not captured in prior years. We also reviewed the underlying activities and costs drivers for these cost categories and find them to be necessary and supported by the evidence. Thus, we find that SDG&E's forecasts for: (a) Other Services, (b) Service Maintenance, (c) Tools, Fittings & Materials, (d) Electric Support, and (e) Cathodic Protection are reasonable and should be approved.

⁵⁶ Exhibit 404 at 6.

Opposed Forecasts

ORA and CUE had alternative recommendations to SDG&E's forecasts for: (a) Leak Survey, (b) Locate & Mark, (c) Main Maintenance, (d) Supervision & Training, and (e) Measurement & Regulation.

For Leak Survey, we find the underlying activities to be necessary and the forecast methodology utilized reasonable and reflective of projected costs for the TY. Regarding CUE's request to move to a three-year inspection cycle and to require a field comparison using Picarro leak detection technology, we find that these requests are outside the scope of this GRC and are being addressed in R.15-01-008, the Gas Leak Abatement OIR addressing the requirements imposed by SB 1371. As for CUE's recommendation to increase funding for the Aldyl-A pipelines surveyed per year, we find SDG&E's forecast to be more appropriate as it is based on updated data on how many miles a patroller can survey in one work day.⁵⁷

For Locate & Mark, ORA recommends using 2016 costs plus adjustments for RAMP-related incremental activities. We reviewed historical costs and find that costs have generally been increasing despite the decrease from 2014 to 2015. In addition, recorded data from 2017 which we find helpful in this case in shedding light on the cost trend shows that costs increased further from 2016 to 2017. Moreover, additional costs are expected from SB 661 (the Dig Safe Act of 2016) which requires additional notification from excavators. With regards to CUE's proposal, we find SDG&E's calculations, which incorporated incremental

⁵⁷ Exhibit 14, Response to CUE Data Request CUE-SEU-DR-08, Appendix B at GOM-B-3.

RAMP-related activities into its linear trend forecast to avoid double-counting, to be more reasonable.

ORA's recommends using 2016 recorded costs for Main Maintenance and argues that costs have been fluctuating from 2012 to 2016. However, as shown in Figure GOM-03,⁵⁸ we find that costs have generally been increasing even though costs decreased slightly from 2013 to 2014. In addition, recorded costs in 2017 support this trend. Thus, we find that SDG&E's linear trend forecast methodology to be appropriate in this case. CUE proposes an increase to SDG&E's proposed costs in connection with its capital requests associated with Aldyl-A pipe replacements and steel pipe replacements. However, SDG&E does not foresee significant O&M costs associated with these capital proposals as the pipes that are being replaced are generally in the same O&M environment and location.⁵⁹ Based on the above, we find it reasonable to approve SDG&E's forecast for Main Replacements.

ORA objects to the incremental funding of \$0.154 million for three field supervisors under the Supervision & Training workgroup. ORA explains that this incremental funding should already be captured in the increase from 2015 to 2016 costs where the increase was close to \$1.2 million. SDG&E explains that activities in the TY are expected to increase over the base year from which the forecast was based hence the incremental adjustment. However, we find that SDG&E does not explain why costs from 2015 increased by around 50 percent in 2016 and so we find it reasonable to agree with ORA that this increase already

⁵⁸ *Id.* at GOM-20.

⁵⁹ Exhibit 14 at GOM-22.

captures the incremental funding being requested in this GRC. Therefore, we find that SDG&E's forecast for Supervision & Training should be reduced by \$0.154 million to \$3.839 million.

With regards to Measurement & Regulation, Table 9-5 of Exhibit 404 shows that costs have been increasing even though there was a slight decrease of \$34,000 between costs in 2014 and 2015. In addition, SDG&E's linear trend forecast incorporates additional costs for RAMP-related mitigations, as well as increased maintenance from aging station components and growth of the gas distribution system. Therefore, we find SDG&E's forecast to be reasonable and should be approved.

Summary for O&M costs

To summarize, we find that all of SDG&E's O&M forecasts should be approved except for Supervision & Training, which should be reduced from \$3.993 million by \$0.154 million to \$3.839 million.

7.2.1.3.2. Asset Management and Operations Management

Costs for both Asset Management and Operations Management were based on TY2016 recorded costs because base costs are expected to remain relatively flat. Incremental adjustments were added to Asset Management to reflect growth in activity to support SDG&E's gas GIS system. Incremental adjustments were also added to Operations and Management to implement computer terminal-based training and training for instructional design. We reviewed the forecasts and find them to be reasonable and supported by the evidence. Parties do not object to SDG&E's forecast for these two cost categories. Therefore, we find that SDG&E's forecasts for Asset Management of \$2.169 million and \$4.510 for Operations and Management should both be approved.

7.2.2. Capital

As stated previously, SDG&E's capital forecasts are \$50.666 million for 2017, \$91.606 million for 2018, and \$110.993 million for 2019. The table below provides a breakdown of the requested capital costs. As is the case with SDG&E's O&M workgroups, many of SDG&E's capital workgroups have the same headings, primary functions, activities, and cost drivers as their corresponding workgroups described and discussed in the SoCalGas portion and so reference to the SoCalGas section describing the cost center functions and activities is made whenever appropriate.

Capital	2017⁶⁰	2018	2019
New Business	\$6,376,000	\$8,217,000	\$7,805,000
System Minor Additions, Relocations & Retirement	\$3,694,000	\$3,694,000	\$3,694,000
Meter & Regulator Materials	\$7,077,000	\$7,468,000	\$7,283,000
Pressure Betterments	\$1,695,000	\$1,695,000	\$1,695,000
Distribution Easements	\$38,000	\$38,000	\$38,000
Pipeline Relocations – Freeway & Franchise	\$6,665,000	\$6,665,000	\$6,665,000
Tools & Equipment	\$2,219,000	\$2,219,000	\$2,219,000
Code Compliance	\$2,549,000	\$1,149,000	\$1,174,000
Replacement of Mains & Services	\$5,968,000	\$16,940,000	\$26,226,000
Cathodic Protection	\$5,450,000	\$5,656,000	\$5,861,000
Regulator Station Improvements & Other	\$1,688,000	\$20,509,000	\$25,633,000
CNG Station Upgrades	\$0	\$2,617,000	\$2,617,000
Local Engineering	\$7,247,000	\$14,739,000	\$20,083,000
Total	\$50,666,000	\$91,606,000	\$110,993,000

7.2.2.1. New Business

See section 7.1.3.1. in the SoCalGas section. For SDG&E, New Business costs were forecast using a zero-based methodology.

7.2.2.2. System Minor Additions, Relocations, and Retirement

This workgroup covers expenditures not covered in other cost categories that are required to maintain continued integrity of the gas distribution system. Examples of activities are gas distribution main and service additions,

⁶⁰ The following 2017 capital forecasts were revised to the following amounts in the Update Testimony (Exhibit 514) at Attachment I: New Business \$8.078 million, System Minor Additions, Relocations & Retirement \$8.838 million, Meter Regulator Materials \$2.664, Pressure Betterment \$0.800 million, Pipeline Relocations – Freeway & Franchise \$15.341 million, Tools & Equipment \$2.565 million, Code Compliance \$1.840 million, Replacement of Mains & Services \$16.151 million, Cathodic Protection \$7.705 million, Regulator Station Improvements & Other \$2.337 million, CNG Station Upgrades \$0.406 million, Local Engineering \$8.994 million.

relocations, and abandonments due to customer requests. Costs were forecast using a five-year historical average.

7.2.2.3. Meter and Regulator Materials

This workgroup is responsible for the capital material expenses for purchasing new residential, commercial, and industrial gas meters and pressure regulators. Meters and regulators are generally installed or replaced due to new business installations, routine replacements, and planned meter and regulator replacements. Costs were forecast using a zero-based methodology.

7.2.2.4. Pressure Betterments

See section 7.1.3.2. in the SoCalGas section. Similar to SoCalGas, costs were forecast using a five-year historical average.

7.2.2.5. Distribution Easement

This workgroup provides funding for easements on private property or public lands. This includes survey and mapping, document research and preparation, and negotiations in addition to easement acquisitions. A three-year average was utilized due to fluctuations from year to year.

7.2.2.6. Pipeline Relocations – Freeway and Franchise

See sections 7.1.3.9. and 7.1.3.10. in the SoCalGas section. Similar to SoCalGas, costs were forecast using a five-year historical average.

7.2.2.7. Tools and Equipment

See section 7.1.3.13. in the SoCalGas section under the “Capital Tools” heading. For SDG&E, costs were forecast using a five-year average instead of a linear trend.

7.2.2.8. Code Compliance

This project provides funding for upgrades and additions to facilities to maintain compliance with minimum federal and state safety standards for gas

pipelines, in particular, those prescribed under 49 Code of Federal Regulations §192 and GO 112-F. Costs were forecast using a three-year average plus incremental additions.

7.2.2.9. Replacement of Mains and Services

See sections 7.1.3.4. and 7.1.3.5. in the SoCalGas section. SDG&E utilized a three-year average to develop its forecasts whereas SoCalGas utilized a five-year average.

7.2.2.10. Cathodic Protection

See section 7.1.3.8. in the SoCalGas section. Similar to SoCalGas, SDG&E developed its forecasts for Cathodic Protection utilizing a five-year liner trend.

7.2.2.11. Regulator Station Improvements and Other

This project provides funding for capital projects not captured in other workgroups that improve safety, compliance with regulations, and improvement to performance and reliability. Examples are upgrades to gas distribution fittings, valves, regulator stations, and other safety improvements to the gas distribution facilities. A three-year average was utilized to develop the forecasts. Certain RAMP-related upgrades and improvements are also included in this project as incremental additions to the base forecast.

7.2.2.12. CNG Station Upgrades

The Compressed Natural Gas (CNG) project will provide installations and upgrades to public access CNG stations that serve the use of CNG vehicles in Southern California. According to SDG&E, CNG stations are used by private vehicle owners, military base vehicles, refuse trucks from the City of San Diego, buses, taxi companies, and private companies. SDG&E plans to add an additional station each in 2018 and 2019. A zero-based methodology was used to develop SDG&E's forecasts.

7.2.2.13. Local Engineering

This project will provide a broad range of services in support of field capital asset construction. Local Engineering is composed technical planning, project management, and engineering activities. Technical planning and project management refer to activities in support of a capital project such as planning, project drawings, third-party services, and estimating work order costs. Engineering activities refer to activities such as analysis, development of designs and specifications, assessment impacts, etc. According to SDG&E, costs tend to fluctuate based on the volume of construction and so a zero-based methodology was used to develop the forecasts using Local Engineering's historic capital expenditures with respect to the total direct expenditures across all Gas Distribution capital budget codes except for Meter and Regulator Materials and Tools & Equipment.

7.2.2.14. Position of Intervenors

ORA, CUE, and TURN provided comments to SDG&E's capital requests.

ORA recommends using 2017 recorded costs for all capital projects and proposes reductions to the 2019 forecast for Replacement of Mains & Services and Regulator Station Improvements & Other. ORA also recommends a different method for calculating Local Engineering costs which results in a lower forecast for 2018 and 2019.

CUE proposes an increase of \$1.844 million to SDG&E's forecast in 2019 for Cathodic Protection and an increase of \$3.718 million to the base forecast for Regulator Stations. CUE also recommends an additional 25 percent or \$14.771 million to SDG&E's forecast for Replacement Mains & Services in 2019.

TURN recommends removal of \$4,008 in clothing and gear provided during safety fairs and civic and community events from 2016 costs.

7.2.2.15. Discussion

ORA's Recommendation to Use 2017 Recorded Costs

As it did for SoCalGas' capital projects, ORA recommends using 2017 recorded costs instead of SDG&E's 2017 forecasts for all of SDG&E's proposed capital projects for Gas Distribution. As we discussed in section 7.1.3.17. in the SoCalGas portion, we find that selectively applying 2017 recorded costs in only certain instances but not in others may lead to inconsistent results and that it is not practical to update all data in the GRC because of the vast amounts of data included in the application. While we recognize that there are instances where it is prudent, necessary, and reasonable to apply select updated data in certain instances. In this case, we find it reasonable and consistent to apply the 2017 forecasts for all the capital projects.

Approved Forecasts

We reviewed all of SDG&E's proposed capital projects including SDG&E's proposed costs, underlying activities, cost drivers, and forecast methodologies utilized to develop the forecasts for 2017, 2018, and 2019. We reviewed the testimony presented, the accompanying workpapers that provide specific details each project, pertinent sections of the RAMP report associated with the three RAMP risks being mitigated, as well as the arguments, recommendations, and counter-proposals raised by parties in testimony and briefs.

Based on our analysis and review of each proposed project, we find the following capital projects: (a) New Business; (b) System Minor Additions, Relocations & Retirement; (c) Meter & Regulator Materials; (d) Pressure Betterments; (e) Distribution Easements; (f) Pipeline Relocations - Freeway & Franchise; (g) Tools & Equipment; (h) Code Compliance; (i) Cathodic Protection;

and (j) Regulator Stations & Other to be necessary and also find the requested funding levels for the above projects to be reasonable.

The above projects were not opposed by parties except for a proposed increase by CUE to Cathodic Protection in 2019. For most of the projects, projected costs for 2017, 2018, and 2019 are close to 2016 recorded costs with significant reductions in costs for System Minor Additions, Relocations & Retirement and Pipeline Relocations. Costs were somewhat higher for Meter & Regulator Materials because of increases in new business and for Tools & Equipment because of activities aimed at mitigating risk to employee and public safety.

We find that SDG&E provided sufficient evidence to support and justify the above-mentioned projects and we find that these projects support system reliability of SDG&E's gas distribution system, promote safety, and necessary services to its customers. We also find the various forecast methodologies utilized to be reasonable and find that the requested forecasts should be approved.

CUE proposes an increase of \$1.844 million to SDG&E's forecast for Cathodic Protection in 2019 citing lagging performance in Cathodic Protection efforts. SDG&E cited various activities that it has undertaken in recent years including proposed enhancements pursuant to the RAMP process. We find that SDG&E's response adequately addresses and refutes CUE's allegation, which was not supported by more substantive and factual data and information.

ORA does not object to the 2018 forecast for Regulator Stations but recommends the same funding level for 2019. The base expense for Regulator Stations & Other is \$0.762 million for 2017, 2018, and 2019, which is around the same level as 2016 recorded costs of \$0.624 million. A majority of the forecast

however consists of funding for four proposed projects that are RAMP-related. These are the Dresser Mechanical Coupling Removal, Oil Drip Piping Removal, Replacement of Buried Piping and Vaults, and the Closed Valves Between Medium-Pressure and High-Pressure Systems (Closed Valves Project) that will verify, excavate, and replace closed and locked valves currently connecting high-pressure piping to medium-pressure piping in order to improve the safety and reliability of the system. ORA does not object to the necessity of funding level for proposed projects but notes that the Close Valves Project will not be completed until 2022 which SDG&E affirmed. However, funding for the project will still be necessary for the portion of the project that is scheduled for this GRC cycle. The Commission recognizes that large-scale projects begun in one GRC cycle are sometimes completed in another GRC cycle. While the project will not be in service at the end of this GRC cycle, the funds authorized will be captured in Allowance for Funds Used During Construction. CUE proposes an increase of \$3.718 million to the base funding for Regulator Stations but we find this unnecessary at this time in light of the four incremental RAMP-related projects that are being authorized and prioritized. In addition, SDG&E's internal parts replacement program for regulators and related infrastructure schedules replacement of parts at regular intervals which, according to SDG&E, has proven useful in extending the useful lives of regulators and related infrastructure.⁶¹ Based on the above, we find it reasonable to approve SDG&E's forecasts for Regulator Stations & Other.

⁶¹ Exhibit 14 at GOM-42.

Modified Forecasts

We find that SDG&E's forecasts for Replacement Mains & Services and Local Engineering should be modified as discussed below.

ORA does not object to the 2018 forecast for Replacement Mains & Services but recommends the same funding level for 2019. ORA states that SDG&E does not justify a 55 percent increase in the 2019 forecast relative to 2018.

Table GOM-12 provides a breakdown of SDG&E's requested costs for Replacement Mains & Services in 2018, and 2019.⁶² The table shows that base expenses are projected to be the same but costs for Vintage Steel Replacement of \$5.486 million in 2018 are projected to increase to \$7.387 million in 2019 and costs for Pre-1933 Threaded Steel Replacement of \$7.386 million in 2018 are projected to increase to \$14.771 million in 2019. We find the projected increase in costs for Vintage Steel Replacement to be reasonable but find the projected increase in costs for Pre-1933 Threaded Steel Replacement in 2019 to around double the amount projected for 2018 is not adequately supported by the evidence presented by SDG&E despite the schedules and funding levels it submitted, especially considering that \$0 was projected for 2017. Instead, we find it more reasonable to authorize the same funding level of \$7.386 million for Pre-1933 Threaded Steel Replacements for both 2018 and 2019 to ensure that SDG&E will be better able to accomplish the projected work in both years. In addition, SDG&E did not present compelling arguments why the level of work projected for 2019 needs to be completed by that time and why it did not begin the work in 2017 if it was such a high priority. CUE proposes an increase of \$11.308 million

⁶² *Id.* at GOM-31.

to SDG&E's requested amount for 2019 which we reject for similar reasons explained above in addressing ORA's recommendation regarding the 2019 forecast. Based on the above, we find that SDG&E's requested amounts for 2017 and 2018 for Replacement Mains & Services should be approved but find that the 2019 forecast should be reduced from \$26.226 million to \$18.835 million.

For Local Engineering, we agree that costs are influenced by the total construction costs and agree with the methodology used of applying the average percentage of Local Engineering costs to the total construction costs with exclusions to costs for Meter and Regulator Materials and Tools & Equipment. We also have no objections to the incremental costs for the cathodic protection system evaluation.

However, SDG&E applied the average percentage of Local Engineering costs relative to total construction from 2012 to 2016 whereas ORA recommends using the average ratio from 2014 to 2017. ORA presents the percentages from 2012 to 2017 in Exhibit 404 which are 23.9 percent, 24.6 percent, 19.8 percent, 18.4 percent, 21.7 percent, and 14.62 percent respectively.⁶³ We reviewed the above percentages and find that there appears to be a significant enough difference in the percentages from 2012 and 2013 as compared to other years. SDG&E states that ORA does not present any evidence to support its recommendation but neither does it present sufficient evidence to explain the change in percentage level from 2014 onwards. Between SDG&E and ORA, we find that SDG&E has the burden of supporting its forecasts and proposed costs. However, consistent with the period for the forecast methodology, we find it

⁶³ Exhibit 404 at 37.

reasonable to only include the average percentages from 2015 to 2017, which is 18.24 percent. Therefore, we find it reasonable to modify SDG&E's forecast methodology for Local Engineering by applying an 18.24 percent multiplier instead of 21.40 percent to direct capital expenditures net of Regulator Materials and Tools & Equipment. SDG&E should re-calculate its forecasts using the above multiplier.

Regarding the request for CNG Station Upgrades, we find that the request includes the addition of new refueling stations in 2018 and 2019 as discussed in section 7.2.2.12. We find that these additions are not upgrades to existing stations. In addition, we find that the addition of new refueling stations is not supported by the procurement of additional vehicles. The procurement of new NGVs is discussed in the Fleet Services section. Therefore, we find it reasonable to deny to requested amounts for CNG Station Upgrades of \$2.617 million each for 2018 and 2019.⁶⁴

Other Issues

TURN raises the same argument as it did in the SoCalGas portion concerning clothing and other gear containing the utility's name and logo (excluding uniforms and hard hats) and argues that these should not be funded by ratepayers. For Gas Distribution, the amount in question for 2016 was \$4,008.⁶⁵ We make the same findings and conclusions as we did in the SoCalGas section concerning these items that are used at safety fairs and other civic and community events so customers and other members of the public can easily

⁶⁴ O&M funding for existing CNG stations was authorized under Gas Distribution - Field Operations, Measurement and Regulation.

⁶⁵ Exhibit 494 at 77 to 78.

identify SoCalGas employees in case they have questions or concerns. In this case, the amount in question is also a nominal amount which we find to be reasonable. Based on the above, we find it reasonable to deny TURN's proposal to remove \$4,008 for clothing and gear from 2016 costs.

8. Gas System Integrity

Gas System Integrity is the division/business unit responsible for creating and issuing policies and standards that establish and validate compliance with laws, regulations, internal policies, and best practices. It works closely with other business units towards a shared goal of providing clean, safe, and reliable natural gas service at reasonable rates.

8.1. SoCalGas

The total forecast for TY2019 is \$32.904 million which is \$19.936 million greater than base year levels. This is inclusive of \$0.204 million in savings from FOF. Pursuant to D.16-06-054, costs associated with the Aliso Canyon gas leak incident are not included in the forecast and are removed from historical information used by impacted witnesses.

Certain costs included in this section are RAMP-related costs supporting activities that mitigate key risks identified in the RAMP Report. The key risks being mitigated are catastrophic damage involving third-party dig-ins, safety, catastrophic damage involving high-pressure and medium-pressure pipeline failure, workforce planning and records management. RAMP-related costs are estimated at \$22.753 million with \$14.913 million representing incremental costs associated with increased risk mitigation efforts associated with the RAMP process.

SoCalGas is also requesting \$34.970 million in 2017, \$38.000 million in 2018, and \$36.223 million in 2019 for IT-related capital projects.

8.1.1. Non-Shared Costs

Total non-shared costs forecast for TY2019 is \$15.640 million⁶⁶ which is \$10.865 million higher than 2016 adjusted, recorded costs.

8.1.1.1. Gas Operations Staff & Training

The forecast for Gas Operations Staff & Training is \$4.734 million using the base year as a basis and then adding incremental costs. Activities in this category consist of various trainings necessary to follow and comply with applicable laws, regulations and standards, and to help maintain the safety of the workforce and the public. Leadership training and training to develop various technical skills are also included in this category.

8.1.1.2. Pipeline Safety & Compliance

The forecast for Pipeline Safety & Compliance is \$2.890 million and was derived using base year costs plus incremental funding. This group is the lead for responding to and complying with the Commission's Safety and Enforcement Division (SED) audits, communications, and inquiries. The group also serves as a centralized gas information center for SoCalGas and includes the Quality and Risk Management group that performs quality assurance and quality control activities for pipeline safety and compliance activities on gas utility assets.

8.1.1.3. Damage Prevention

The forecast for Technical Services is \$1.681 million.⁶⁷ This category includes implementation of a federally mandated Public Awareness Program⁶⁸

⁶⁶ This includes an adjustment of \$42,000 in the Update Testimony for the public awareness forecast and \$2,000 rounding for Gas Ops Staff & Training and Asset Management.

⁶⁷ The forecast for Technical was revised from \$1.641 to \$1.681 in the Update Testimony (Exhibit 514) at Attachment H.

⁶⁸ Prescribed in 49 CFR § 192.616.

that provides certain risk mitigation measures for enhanced public safety. The program must be comprehensive to reach all areas which SoCalGas transports gas and must include activities to advise municipalities, school districts, businesses, and residents of pipeline facility locations. SoCalGas also intends to boost awareness activities to lower the number of damages to its system and to especially mitigate third-party damages.

8.1.1.4. Asset Management

The forecast for Asset Management is \$2.503 million using a five-year average. Asset and data management require computer-based work management and document management systems and technical computing management and support systems. Part of the activities includes maintaining and upgrading software applications.

8.1.1.5. Gas Contractor Controls

The forecast for Gas Contractor Controls is \$3.830 million using a zero-based method because this department is relatively new. The Gas Control Controls department formulates and promote policy related to construction contractor safety and pipeline safety and quality oversight.

8.1.2. Shared Costs

Total shared costs forecast for TY2019 is \$17.306 million which is \$9.113 million higher than 2016 adjusted, recorded costs. The cost categories for shared services are identical to those in the non-shared services section but the activities representing the shared services differ.

8.1.2.1. Gas Operations Staff & Training

The forecast for Gas Operations Staff & Training is \$1.364 million. This includes cost centers for: (a) the VP of System Integrity and Asset Management which provides leadership, guidance, and policies and includes both labor and non-labor costs; (b) Field Technologies which evaluates new tools and

technologies that enhance or replace existing processes or tools to provide enhanced benefits such as improved efficiency and improved safety; and (c) Gas System Integrity Staff & Programs which includes salaries of a director and staff as well as supplies and materials. All costs were forecast using a five-year average plus incremental costs.

8.1.2.2. Pipeline Safety & Compliance

The forecast for Pipeline Safety & Compliance is \$4.593 million. Cost centers included in the forecast are: (a) Pipeline Safety Oversight which provides centralized incident evaluation through monitoring and documenting the progress of corrective actions and monitoring of compliance with federal and state regulatory requirements; (b) Pipeline Safety & Compliance Manager which serves as the point of contact with SED and audits and manages responses to SED inquiries and includes labor and non-labor costs; (c) Operator Qualification which schedules qualification activities, reviews and audits contractor qualification programs, keeps qualification records, and monitors records for possible compliance issues; and (d) Quality Risk which performs quality assurance and quality control activities for various pipeline safety and compliance activities on gas utility assets. All the forecasts were prepared utilizing a base year plus incremental costs method.

8.1.2.3. Damage Prevention

The forecast for Damage Prevention is \$2.383 million. Cost centers included here are: (a) Shared Public Awareness Activities which conducts central management of SoCalGas' and SDG&E's Public Awareness Plans; and (b) Pipeline Systems Construction Policy which develops system-wide policies and practices concerning high-pressure construction and a damage prevention program focusing on preventing excavation damages to SoCalGas' underground

pipelines. The forecasts were developed using base year plus increments and a five-year average respectively.

8.1.2.4. Asset Management

The forecast for Asset Management is \$6.416 million. Included costs centers are: (a) Business Process Enterprise System Support (ESS) Implementation and Mobile Support which is responsible for material traceability, management and development of departmental websites; (b) Applications which provides support for computer programs and systems not covered by the Information Technology group; (c) ESS Production Support which develops and maintains business applications that are used to support Gas Transmission and Gas Storage operations; (d) Work Management and Databases which provide operational system support to field and other functions; (e) Contract Maintenance which is responsible for software licenses and maintenance contracts that support the systems and applications of various organizations; and (f) Enterprise Geographic Information System (GIS) which gathers data sets addressed by the GIS system and includes synchronization of GIS and high-pressure pipeline database. All the forecasts were developed using a five-year average with incremental costs being added for expanded work and additional staffing and resources.

8.1.2.5. Gas Contractor Controls

The forecast for Gas Contractor Controls is \$2.550 million. This organization provides a centralized records management and program organization of daily tasks and activities that are performed. The forecast was developed using a zero-based methodology because the program was newly created in late 2016.

8.1.3. IT Business Unit Capital Projects

SoCalGas is requesting \$34.970 million in 2017, \$38.000 million in 2018, and \$36.223 million in 2019 for IT-related capital projects. Appendix B of Exhibit 84 contains a list of the 29 IT-related projects being requested. Detailed descriptions of each project are included in the capital workpapers of Exhibit 302.⁶⁹ The projects include RAMP-related incremental upgrades and various IT upgrades that provide increased functionality, customization, and migration from obsolete systems or systems that are no longer supported.

8.1.4. Position of Intervenors

Comments regarding this section were provided by ORA, CUE, and OSA.

For both shared and non-shared costs, ORA recommends using the 2016 adjusted, recorded amount as the basis for costs rather than the various methods utilized by SoCalGas. ORA does recognize that increased costs may result due to new programs and requirements and adds the incremental costs to the 2016 costs resulting in \$4.775 million recorded costs plus \$2.683 million incremental costs for non-shared and \$8.193 million recorded costs plus \$3.198 million incremental costs for shared services resulting in a total recommended amount of \$18.853 million⁷⁰ compared to the \$32.904 million requested by SoCalGas.

CUE does not contest any of the proposed costs in this section but initially recommended that the Commission direct SoCalGas to implement proposed training or alternatively, make the proposed training subject to a one-way

⁶⁹ Exhibit 302 at 551 to 818.

⁷⁰ Exhibit 407 at 10.

balancing account treatment. This request was not raised again in CUE's opening brief.

OSA makes a number of related recommendations which centers on SoCalGas being required to implement American Pipeline Institute (API) Recommended Practice (RP) 1173 and recommendations for making the Pipeline Safety Management System (PSMS) more effective and including the PSMS as part of the next RAMP filing as well as requiring a third-party audit of implementation before the filing of its next GRC application.

8.1.5. Discussion

We first reviewed ORA's recommended methodology of using base year costs as the basis for the forecast and then adding the incremental costs requested by SoCalGas. ORA does not indicate that it disputes any of these incremental costs and even recommends that both non-shared and shared incremental activities be approved.⁷¹ ORA then adds \$2.683 million of incremental costs for non-shared and \$3.198 million incremental costs for shared services or a total of \$5.881 million.

However, ORA does not indicate or explain how it derived these incremental cost totals or whether it ignored incremental costs associated with RAMP. We reviewed the forecast costs and ORA's incremental cost totals appear to be incorrect. For example, the RAMP incremental costs alone total \$14.913 million. SoCalGas also clarifies this point and submitted tables showing that the incremental adjustment it requests for non-shared services total

⁷¹ Exhibit 407 at 9.

\$10.970 million and for shared services the total is \$7.198 million.⁷² Using ORA's methodology of base year plus applying the corrected incremental costs results in a total TY2019 forecast of \$31.136 million for Gas System Integrity which is not too far removed from the \$32.904 being requested by SoCalGas. Therefore, we find it reasonable to deny ORA's recommended amounts as it appears to be based on incorrect incremental costs.

SoCalGas utilized various forecast methodologies in this section but most of the forecasts utilized either the base year or five-year average as the basis from which incremental costs were then added. As shown in Table 12-4 of Exhibit 407,⁷³ total costs from 2012 to 2016 do not have much variance. Following this, we find that using either base year or the five-year average as the basis for TY2019 forecasts is reasonable as either method produces relatively similar results. The key element to consider therefore is whether the incremental costs are justified.

Reviewing the incremental costs described in Exhibit 84, we note that most of the costs are RAMP-related with \$14.913 million out of the \$18.168 total representing RAMP-related incremental costs. We reviewed the activities relating to RAMP and find that aside from new programs, many of the risk mitigation and safety-related activities that were already being performed historically are being enhanced, especially activities relating to the prevention of damage from third-parties. In addition, this section seeks to address relatively more RAMP risks than are being addressed in other sections in this decision

⁷² Exhibit 86 Appendix A.

⁷³ Exhibit 407 at 7.

leading to more enhanced risk mitigation activities and in turn, more costs. In addition to the RAMP-related costs, other incremental costs are due to new programs being implemented and programs and activities to address new regulatory requirements.

Based on the above, we find the incremental costs requested to be reasonable and supported by the testimony submitted. We also have no objection to the zero-based methods used for Gas Contractor Controls as this program is relatively new. We therefore have no recommended adjustments to SoCalGas' forecasts and find that the requested Gas System Integrity costs for TY2019 should be authorized.

Regarding CUE's recommendation concerning training costs, we agree with SoCalGas that a one-way balancing account to record training costs is not necessary at this time to allow for a certain degree of flexibility as we continue to evaluate and make refinements to the RAMP process which is being integrated into the GRC for the first time. Also, pursuant to Pub. Util. Code § 591,⁷⁴ the proposed training must be included in SoCalGas' Risk Spending and Accountability Reports as ordered by D.16-06-054.⁷⁵ The training costs that will be authorized in this decision will be submitted as part of the above reports along with a comparison of what was spent and an explanation regarding any discrepancy.

⁷⁴ Pub. Util. Code § 591 (a): The commission shall require an electrical or gas corporation to annually notify the commission, as part of an ongoing proceeding or in a report otherwise required to be submitted to the commissions, of each time since that notification was last provided that capital or expense revenue authorized by the commission for maintenance, safety, or reliability was redirected by the electrical or gas corporation to other purposes.

⁷⁵ D.16-06-054 OP 11(d) at 331 to 332.

With regards to OSA's recommendations, SoCalGas states that it is proactively working, on a voluntary basis, towards the implementation of a PSMS following the recommendations in API RP 1173.⁷⁶ SoCalGas further states that the plan is still in development and that elements thereof are more prudently reviewed first at a high level. SoCalGas adds that implementation should not be rushed to avoid implementation pitfalls. We support and share OSA's goals to advocate for the improvement of Applicants' safety management although as SoCalGas points out, API RP 1173 is not a required practice and some key elements thereof are already being applied by SoCalGas. We agree with SoCalGas that implementing a system-wide PSMS should first be reviewed thoroughly and that a detailed plan must be developed before implementation. Thus, rather than directing and requiring immediate implementation, we find that SoCalGas should instead be directed to submit testimony in its next GRC concerning its findings and the development of its plans concerning the establishment of a system-wide PSMS. We also note that many of OSA's recommendations focus on safety culture enhancements and practices and not revenue requirements. We find that these are better addressed in SoCalGas' next RAMP filing and look forward to OSA's continued participation in SoCalGas' next RAMP and GRC applications.

To summarize, we find that SoCalGas TY2019 forecasts of \$15.640 million for non-shared costs and \$17.306 million for shared costs are reasonable and should be approved.

⁷⁶ Exhibit 86 at OR-17 to 20.

We reviewed each of the 29 IT-related capital projects being requested by SoCalGas and find the projects to be necessary and supported by the evidence presented with the exception of two projects namely the Click Enhancement Project (\$5.137 million in 2017, \$3.898 million in 2018, and \$2.000 million in 2019) and the Field Data Collection with eForm project (\$1.903 million each for 2018 and 2019). For these two disapproved projects, SoCalGas seeks to improve on the existing IT but fails to explain why those systems are no longer adequate to complete the same tasks. SoCalGas states that the projects will make tasks easier or improve certain aspects but provides insufficient detail in its workpapers to show that the current systems are unable to perform the same tasks or how the improvements will change the performance capabilities of the existing systems. Therefore, we find it reasonable to deny the above-named projects which results in \$29.833 million in 2017, \$32.199 million in 2018, and \$32.320 million in 2019 that should be approved.

8.2. SDG&E

SDG&E's total forecast for TY2019 is \$1.558 million which is \$1.407 million greater than recorded costs of \$0.151 million in 2016. A portion of the requested costs are for RAMP-related projects and activities to mitigate key risks identified in the RAMP Report. The key risks being mitigated are: (a) catastrophic damage involving third-party dig-ins; (b) employee, contractor, and public safety, and (c) records management. RAMP-related costs, which are estimated at \$1.352 million, with \$1.227 million representing incremental costs.

SDG&E is also requesting \$0.110 million in 2017 for the Gas Operations Performance Analytics Phase 3 project.

8.2.1. Non-Shared Costs

Total non-shared costs for TY2019 is \$0.958 million and is \$0.807 million higher than 2016 recorded costs. Non-shared costs are composed of Asset Management, Pipeline Safety & Compliance, and Damage Prevention and the forecasts for TY2019 are \$0.127 million, \$0.106 million, and \$0.726 million respectively.

Asset Management

Costs were forecast using a zero-based method because this activity does not have historical costs. SoCalGas plans to implement a company-wide pipeline safety management system that complies with API RP 1173 on a voluntary basis.

Pipeline Safety & Compliance

Costs were forecast using a base year method plus incremental additions for increased program and field audits, data requests, field visits, and discussions with SED about best practices.

Damage Prevention

Costs were developed using an adjusted forecast as SDG&E plans to increase the volume of current efforts relating to public awareness programs that aim to reduce damage to SDG&E's systems caused by third-parties. Other activities conducted are the same as those described in section 8.1.1.3 in the SoCalGas section.

8.2.2. Shared Costs

Shared costs of \$0.600 million are for Codes and Standards which supports the development and integration of gas standards for SDG&E and SoCalGas. Gas standards policies help the two utilities meet and comply with regulatory obligations, allow for information exchange, and provide consistency with respect to gas standards. Costs were forecast using a zero-based methodology.

8.2.3. IT Business Unit Capital Projects

SDG&E is requesting \$0.110 million in 2017 for the Gas Operations Performance Analytics Phase 3 project. The project will expand the existing reporting platform that will provide more robust and easy to use reports as well as other operational efficiencies.

8.2.4. Discussion

Comments were provided by OSA, ORA, and CUE.

OSA makes the same recommendations concerning the implementation of API RP 1173 and making PSMS as part of the next RAMP filing as well as requiring a third-party audit of implementation before the next GRC filing. And we make the same findings and conclusions as we discussed in the SoCalGas section under section 8.1.4. API RP 1173 is not a required practice but SDG&E is implementing these standards on a voluntary basis. Also, many of OSA's recommendations are better addressed in SDG&E's next RAMP filing and we encourage OSA's participation in that proceeding as well as in SDG&E's next GRC.

ORA recommends reducing costs for Damage Prevention (\$0.726 million) to \$0.375 million while CUE recommends increasing it to \$1 million.

ORA recommends using the highest recorded cost during the last five years but most of the TY2019 forecast are for incremental activities for increased risk mitigation efforts to reduce damage caused by third-parties. Thus, we find that ORA's analysis does not take into consideration new activities resulting from the RAMP process which is being incorporated into the GRC for the first time. As a result, we find SDG&E's forecast to be more reasonable.

On the other hand, CUE recommends \$1 million for increased 811 advertising under Damage Prevention. However, SDG&E's approach is to

balance spending between the advertising activities and Locate and Mark activities under the Gas Distribution section that include locating and marking underground pipelines, conducting job observations, and performing pothole operations and depth check. Both activities contribute to reducing damage from third-party dig-ins and we find SDG&E's approach of requesting funding for both activities to be reasonable. Thus, we find that CUE's request to increase SDG&E's requested amount is not necessary at this time.

To summarize, we find SDG&E's total TY2019 forecast of \$1.558 million for O&M costs reasonable and should be approved. We reviewed SDG&E's request for an IT-related capital project and find the request reasonable and should be approved. No party objected to the proposed project.

9. Gas Transmission Operations (O&M)

This section addresses the day-to-day expenses associated with operating and maintaining Applicants' natural gas transmission system. This section only covers O&M expenses. Capital costs are addressed in section 10 of the decision.

9.1. SoCalGas

SoCalGas' Gas Transmission organization is responsible for the safe operation of approximately 2,918 miles of high-pressure gas pipeline and nine compressor stations.⁷⁷ Aside, from operating safely, the Gas Transmission organization also aims to comply with legal and regulatory requirements and provide customers with reliable natural gas service at a reasonable cost.

⁷⁷ According to SoCalGas, the Department of Transportation (DOT) uses engineering criteria to define transmission lines as opposed to the functional approach utilized by SoCalGas and so the length of SoCalGas' gas pipeline is different using DOT standards.

The total forecast for Gas Transmission Operations for TY2019 is \$51.934 million which includes \$5.095 million in savings from FOF initiatives and excludes costs relating to the Aliso Canyon gas leak incident pursuant to D.16-06-054. All costs were forecast using a five-year average and are adjusted for future period incremental changes as applicable. Certain costs are associated with risks identified in the RAMP Report. Key risks identified relate to catastrophic damage involving high-pressure pipeline failure and activities to mitigate these risks are include activities relating to pipeline operation and technical services. Mitigation activities that are RAMP-related are estimated at \$23.923 million.

9.1.1. Non-Shared Costs

9.1.1.1. Gas Transmission Pipelines

The forecast for Gas Transmission Pipelines is \$14.463 million which is \$3.229 million less than 2016 adjusted, recorded costs. Incremental costs for support staffing, leakage investigation and mitigation, cathodic protection maintenance and repair, and incremental maintenance were added to the five-year historical average.

The Gas Transmission Pipelines group is responsible for safe day-to-day operation and maintenance of gas transmission pipeline facilities and related infrastructure. This includes maintaining equipment at pipeline receipt points, valve control stations, delivery transfer points, monitoring and control facilities, etc. This group also performs leak surveys of all transmission pipeline facilities, develops and implements gas handling procedures, investigates gas quality issues, provides emergency services, and other related functions.

9.1.1.2. Compressor Stations

The forecast for Compressor Stations is \$9.988 million which is \$0.256 million more than 2016 adjusted, recorded costs. Incremental costs for various support staffing were added to the five-year historical average.

The Compressor Stations group is responsible for safe and reliable day-to-day operation and maintenance of nine compressor station facilities and related infrastructure. This includes maintenance of compressor engines, ancillary equipment, monitoring, metering, and control facilities, and other related equipment. The group is also responsible for developing gas compression O&M procedures, air emission monitoring and testing, conducting inspections, maintaining round-the-clock staffing to respond to compression operation issues, and other related functions.

9.1.1.3. Technical Services

The forecast for Technical Services is \$26.467 million which is \$24.581 million more than 2016 adjusted, recorded expenses. Incremental costs for staffing, satellite monitoring, rights-of-way maintenance, high consequence area (HCA) mitigation, and system reliability project abandonment recovery.

Technical Services activities include design engineering, instrumentation, project support, and environmental services in support of day-to-day operations and maintenance of SoCalGas' gas transmission system. Technical Services is also responsible for right-of-way maintenance, on-site technical expertise and troubleshooting of technical issues.

9.1.1.4. Positions of Intervenors

ORA and TURN object to the forecast for Technical Services but do not oppose the forecasts for Gas Transmission Pipelines and Compressor Stations.

ORA recommends using a five-year average for Technical Services which is \$2.229 million. ORA objects to the incremental cost drivers and argues that these activities are routine in nature and part of day-to-day expenses incurred by a gas transmission and storage company for its operations.⁷⁸ ORA also specifically objects to the HCA mitigation and the system reliability project abandonment recovery associated with the North-South project.

TURN objects to the forecast for Technical Services and recommends disallowance of incremental spending for HCA mitigation, rights-of-way maintenance, and the Southern Gas System Reliability Project abandonment recovery which relate to the denied application for the North-South pipeline. Instead, TURN recommends using a five-year average from 2013 to 2017 which results in \$2.376 million or a reduction of \$24.090 million from SoCalGas' request.

9.1.1.5. Discussion

We reviewed SoCalGas' forecasts for Gas Transmission Pipelines and Compressor Stations and find these to be reasonable and supported by the evidence presented. The amounts requested approximate or are less than base year adjusted, recorded expenses. SoCalGas also provided sufficient testimony concerning the incremental cost drivers and parties did not object to the forecasts. Therefore, we find that the requested amounts for Gas Transmission Pipelines and Compressor Stations should be authorized.

For Technical Services, we find that the appropriate five-year average to consider is from 2012 to 2016 as opposed to TURN's recommendation to utilize 2013 to 2017. The proceeding generally relies on historical data up to the base

⁷⁸ Exhibit 407 at 10 to 12.

year since the application is filed in 2017 and it is not feasible to update all data as it becomes available throughout the course of the GRC. We also find that select updating of data without sufficient reason or justification may cause unfairness as other parties can also request the Commission to consider other updated data selected by parties that favor their position. And while we recognize that the Commission may at times rely on and utilize select base year plus 1 data which in this case is 2017 data, we find that these should be limited to cases when use of such information is reasonable and sufficiently justified. Therefore, we find that the five-year average that should be considered for Technical Services is from 2012 to 2016.

We next consider the incremental costs requested by SoCalGas which are:

Technical Support Staffing: \$0.056 million

Satellite Monitoring: \$0.050 million

HCA Mitigation: \$12.000 million

Contracts and Procurement Support Staffing: \$0.181 million

Rights-of-Way Maintenance: \$5.000 million

North-South Project Abandonment Recovery: \$7.162 million

SoCalGas argues that the above are incremental costs and provide testimony explaining why. Our approach is to examine each one rather than rejecting all of them outright as ORA recommends. We agree that some of the activities proposed are in addition to or incremental to historical costs and that there may be RAMP-related activities that justify the incremental funding.

We reviewed the testimony concerning technical support staffing, satellite monitoring, and contracts and procurement support staffing and find that the incremental funding being requested for these are supported by the evidence. The incremental cost driver concerning the need for additional staffing is similar to requests for the same in other cost categories that are discussed in this section. We also find that the amount corresponding to satellite monitoring was

adequately explained and justified by SoCalGas' testimony. Thus, the requested increments for these activities should be approved.

With regards to HCA mitigation and rights-of-way maintenance, SoCalGas states that the incremental funding requested is associated with mitigating a risk that was identified in the RAMP report which is catastrophic damage involving high-pressure pipeline failure. SoCalGas' testimony explains the necessity of rights-of-way maintenance and HCA mitigation and that it is required to remediate or replace pipeline within two years of a class location change due to encroachment on transmission pipelines.

Recorded costs for HCA mitigation from 2012 to 2016 range from \$0 to \$2.224 million with an annual average of \$0.785 million.⁷⁹ For rights-of-way maintenance, SoCalGas explains that the annual budget has been approximately \$1.5 million but a single project for removal of an abandoned pipeline can potentially consume this amount depending on the amount of abandoned pipeline to be removed.⁸⁰

However, as is the case with many activities that are now designated as being RAMP-related, HCA mitigation and rights-of-way maintenance are activities that were already being performed by SoCalGas prior to the RAMP process. And from our review of SoCalGas' testimony and its arguments raised in briefs, we find that SoCalGas did not sufficiently explain and justify why incremental funding over historical costs is necessary for these two areas such as increased mitigation efforts and activities due to RAMP or other reasons.

⁷⁹ Exhibit 407 at 15.

⁸⁰ Exhibit 26 at EAM-5.

SoCalGas did argue that some of the cost drivers for rights-of-way mitigation are not routine, such as removal of previously abandoned pipelines, span repainting after wildfires, and repair of pipe exposures and road washouts after significant rainfall.⁸¹ In recognition of these non-routine activities as well as consideration of a general increase in mitigation activities resulting from the RAMP process, we find that an increment of \$1.5 million for rights-of-way maintenance representing costs that are 100 percent above the annual average is reasonable. For HCA mitigation, we find that authorizing the highest level of spending during the last five years which is \$2.224 million instead of the annual average of \$0.785 million is reasonable. This results in an increment of \$1.439 for HCA mitigation.

With respect to the \$7.162 million requested for the North-South project abandonment recovery, Exhibit 24 refers us to the joint testimony of witnesses Bermel and Musich in Exhibit 30⁸² which covers SoCalGas' request for cost recovery for the North-South project addressed in section 10 of this decision. Therefore, we reject the request made in this section and address this issue in section 10. SoCalGas argues that the request made in this section is for O&M costs and is distinct from the request made in Exhibit 30,⁸³ but its testimony in Exhibit 24 says otherwise. In any case, SoCalGas' testimony in Exhibit 29 fails to provide sufficient grounds to support its request and we therefore find that the request in this section should be denied.

⁸¹ SoCalGas and SDG&E Opening Brief at 73.

⁸² Exhibit 24 at EAM-18.

⁸³ Exhibit 26 at EAM-8.

To summarize, we find that SoCalGas' requested amount of \$26.467 million for Technical Services should be reduced by \$21.223 million representing reductions of \$10.561 million for HCA mitigation, \$3.5 million for rights-of-way maintenance, and \$7.162 million for the North-South project abatement recovery. This results in an amount of \$5.244 million that should be approved for Technical Services.

9.1.2. Shared Costs

SoCalGas' management personnel provide support to SDG&E's gas transmission operations. A total of \$1.016 million is forecast for shared services which is \$66,000 more than 2016 adjusted, recorded expenses. These costs represent salaries and expenses relating to the provision of shared service functions and are comprised of three cost center organizations. All shared services related to gas transmission are performed by SoCalGas and costs are allocated to SDG&E by each cost center organization. All forecasts were based on a five-year historical average.

9.1.2.1. Director of Gas Transmission

The Director of Gas Transmission provides overall operational leadership and is responsible for O&M performance, regulatory compliance, financial performance, and work measurement reporting. The forecast for TY2019 is \$0.240 million with 9.31 percent being allocated to SDG&E.

9.1.2.2. Field Operations Managers

Field Operations Managers provide departmental operational leadership, staffing management, financial and work measurement, performance and reporting for pipeline and compressor stations, and other related duties. The forecast for TY2019 is 0.419 million of which 21.01 percent is allocated to SDG&E.

9.1.2.3. Technical Services Manager

The Technical Services Manager provides departmental operational leadership, staffing management, and technical support services for both SoCalGas and SDG&E. The forecast for TY2019 is \$0.357 million of which 7.14 percent is being allocated to SDG&E.

9.1.2.4. Discussion

The total forecast for Shared Services is near base year levels being only \$66,000 more. Most of the additional costs are from the Field Operations Managers. Based on our review, we have no objections to SoCalGas' forecast which we find to be supported by the testimony submitted. We also agree with the forecast methodology utilized as well as the allocation of costs between SoCalGas and SDG&E which was based on the number of Gas Transmission organization employees for each of the different shared services cost categories. ORA is the only other party that provided comments to this section and ORA did not have any issue with SoCalGas' forecast. Therefore, based on the above, we find that SoCalGas' request for Shared Costs totaling \$1.016 million should be approved.

9.2. SDG&E

SDG&E's forecast for TY2019 is \$5.110 million which is \$0.740 million more than base year adjusted, recorded costs. The forecast represents projected expenditures for O&M costs in TY2019. Capital-related costs are discussed in section 10 of the decision. The forecast is inclusive of \$52,000 in savings associated with FOF.

9.2.1. Non-Shared Costs

SDG&E's Gas Transmission organization does not perform any shared services activities and so all costs are non-shared. There are three operational functions being supported which are Gas Transmission Pipelines, Compressor

Station, and Technical Services. The functions performed correspond to the three non-shared services operational functions for SoCalGas which have the same names and are discussed in the SoCalGas portion in section 9.1.1. above. All forecasts were also derived using five-year historical averages plus incremental cost estimates. Thus, in this subsection, we only describe the forecast and incremental cost drivers. The description of the functions performed by each cost category corresponds to the SoCalGas portion in section 9.1.1.

Gas Transmission Pipelines

The forecast for TY2019 is \$1.839 million. Incremental cost drivers include staffing, pipeline leakage investigation and mitigation, and right-of-way maintenance.

Compressor Station

The Forecast for TY2019 is \$3.124 million. Incremental cost drivers are mainly for support staffing.

Technical Services

The forecast for TY2019 is \$0.147 million. Incremental cost drivers are for technical support staffing.

9.2.2. Discussion

We reviewed SDG&E's request as well as the testimony submitted and find that the testimony provided is sufficient to support SDG&E's requested amounts. The basic activities to be performed are the same as the activities in SDG&E's prior GRCs. The forecast for TY2019 is not very different from base year levels and the increased amounts are reasonable and adequately explained by the incremental cost drivers described in testimony. The increased costs are mainly due to increased staffing due to increased activities and increased risk mitigation and safety-related activities to be performed. For Gas Transmission

Pipelines, additional leak detection equipment will be added. We also have no issues with the forecast methodology utilized by SDG&E.

ORA is the only other party that provided comments to SDG&E's forecast for Gas Transmission Operations and ORA did not find any issue with SDG&E's forecast. Based on the above, we find that SDG&E's requested amount for Gas Transmission Operations of \$5.110 million should be adopted.

10. Gas Transmission Capital

This section addresses capital expenditures relating to Gas Transmission which include pipelines and appurtenances as well as gas compressor stations which help move gas through transmission pipelines. Applicants state that these capital projects are required for the safe, reliable, and effective operation of their Gas Transmission system. In addition, SoCalGas seeks recovery for costs reasonably incurred in conceiving and pursuing the North-South project which, according to SoCalGas, was proposed to address a recognized reliability risk.

10.1. SoCalGas

SoCalGas requests \$135.413 million in 2017, \$181.837 million in 2018, and \$178.776 million in 2019 for Gas Transmission capital projects. In addition, SoCalGas also requests \$7.162 million each for 2019, 2020, and 2021 to recover costs for the North-South project which it proposes to spread over the three years covering this GRC cycle.

The capital projects being proposed include RAMP-related costs totaling \$8.735 million in 2017, \$15.951 million in 2018, and \$11.509 million in 2019. The RAMP-related projects are linked to mitigating three major safety risks identified in the RAMP Report. These are catastrophic damage involving high-pressure

pipeline failure, physical security of critical gas infrastructure, and climate change adaptation.⁸⁴

Risk mitigation efforts associated with RAMP relate to specific projects or programs. For catastrophic damage involving high-pressure pipeline failure, SoCalGas plans to de-rate, conduct pressure tests, or replace sections of pipeline and conduct preventive maintenance or remediate cathodic protection areas. To mitigate the risk of physical security of critical gas infrastructure, SoCalGas proposes projects to upgrade access control and detection capabilities. Finally, to address risks relating to climate change adaptation, SoCalGas proposes projects that will help mitigate safety-related threats to gas infrastructure from extreme weather events, land movement, and erosion such as the installation of strain gauges near vulnerable gas transmission pipelines that will monitor excessive stresses.

10.1.1. New Pipeline

This project is for the construction of new pipeline to provide the backbone and local natural gas transmission system with additional resiliency, capacity, and reliability in order to serve load and to provide natural gas reinforcement to an existing area.⁸⁵ The forecast for this project is \$8.543 million for 2017, \$7.383 million each for 2018 and 2019 using a five-year average.

10.1.2. Pipeline Replacements

This project is for the replacement of existing pipelines due to various reasons such as condition of the pipeline, class location changes, hazardous

⁸⁴ These RAMP risks are in Chapters SCG-4, SCG-6, and SCG-9 respectively in the RAMP Report.

⁸⁵ Exhibit 30 at MAB-9.

conditions, etc. The forecast for this project is \$30.194 million for 2017, \$26.358 million for 2018, and \$10.499 million for 2019 using a zero-based methodology. A summary of projects currently planned or in the process of being executed are listed in Exhibit 30.⁸⁶

10.1.3. Pipeline Relocations

Pipeline Relocations occasionally occur because of utility agreements with state and local agencies. Locations of pipelines and related facilities may conflict with California Department of Transportation (Caltrans) construction projects, property development, municipal public works, street improvements, rights-of-way, and other contract or franchise agreements. The forecast for this project is \$11.596 million for 2017, \$10.476 million for 2018, and \$5.922 million for 2019 using a zero-based methodology for freeway relocations and a five-year average plus incremental for franchise relocations. A summary of projects currently planned or in the process of being executed are provided in Exhibit 30.⁸⁷

10.1.4. Compressor Stations

SoCalGas states that many of its compressor stations and sub-systems are more than 50 years old require significant upgrades and replacements to maintain operational reliability and system resiliency and also to comply with environmental regulations. The projects that are being planned were categorized as small, medium, and large projects based on the projected costs of a project and include blanket projects comprised of many smaller but related projects. A

⁸⁶ *Id.* at MAB-11 to 12.

⁸⁷ Exhibit 30 at MAB-13 to 15.

majority of the projects are classified as small projects, but two large projects are planned for replacements of the Blythe compressor station and the Ventura compressor station. SoCalGas also includes costs for decommissioning of the Cactus City and Desert Center compressor stations which were constructed in the 1950s and have reached the end of their working lives. The forecast for these projects is \$50.432 million for 2017, \$103.351 million for 2018, and \$116.626 million for 2019. A summary and description of the small, medium, and large projects are listed in Exhibit 30.⁸⁸

10.1.5. Cathodic Protection

Cathodic Protection equipment is used to preserve the integrity of natural gas pipelines, mains, service lines, and underground appurtenances by providing protection against external corrosion. The forecast for Cathodic Protection projects is \$5.000 million for 2017, \$6.235 million for 2018, and \$6.658 million for 2019 using a base year forecast methodology because costs are relatively flat.

10.1.6. Meter & Regulator

The meter and regulator equipment control the flow of natural gas in the transmission pipelines using valves and regulator stations. This equipment is then controlled locally or remotely from a central control system. The forecast for these projects is \$18.938 million each for 2017, 2018, and 2019 using base year adjusted, recorded costs as the activities in 2016 represent activities that will be carried out in 2017 to 2019.

⁸⁸ *Id.* at MAB-17 to 24.

10.1.7. Auxiliary Equipment

Auxiliary Equipment projects include equipment used to support the gas transmission system that is not assigned to a specific project. The projects under this category include physical security upgrades related to RAMP and equipment to monitor land movement. The forecast for these projects is \$10.710 million for 2017, \$9.096 million for 2018, and \$12.750 million for 2019 using a zero-based methodology.

10.1.8. Position of Intervenors

IS initially stated that SoCalGas did not provide enough supporting testimony for the Blythe Compressor Modernization project.⁸⁹ SoCalGas subsequently included more detail in its rebuttal testimony⁹⁰ and IS did not raise this specific issue again in briefs.

ORA proposed different recommendations for 2017 costs for New Pipeline, Pipeline Replacement, Pipeline Relocation, Cathodic Protection, and Meter & Regulator. The ORA proposed figures are shown in Table 12-9 of Exhibit 407.⁹¹

For Compressor Stations, ORA recommends \$24.979 million for 2017, \$92.888 million for 2018, and \$107.168 million in 2019. ORA states that SoCalGas has significantly underspent funds authorized from the prior GRC and has spent only 50 percent of its forecast for 2017. ORA also recommends that funding should only be for specific projects.

⁸⁹ Exhibit 436 at 23 to 24.

⁹⁰ Exhibit 32 Appendix A.

⁹¹ Exhibit 407 at 19.

ORA also recommends that the costs for Auxiliary Equipment be reduced to \$5.744 million in 2017 representing recorded costs for 2017 and \$5.661 million each for 2018 and 2019 representing the five-year average.

10.1.9. Discussion

With respect to the various recommendations made by ORA for 2017 other than for Compressor Stations and Auxiliary Equipment which we shall discuss separately, we find that ORA's recommendations were not supported by the evidence it presented. In addition, SoCalGas cited delays to several projects which resulted in lower 2017 spending for Pipeline Relocation.

Similarly, for Compressor Stations, SoCalGas cited delays involving the Blythe Modernization project which is a large-scale project. From its testimony, SoCalGas indicates that work was conducted for 2016 and 2017, but because of delays, the project will not be placed in service until 2018.⁹² As a result, the funds expended for construction are not yet recorded since the plant is not yet in service. There is no evidence or indication that actual work and construction were not taking place in 2016 and 2017 and we find that it could have been ascertained if engineering or construction work were not being conducted and authorized funds were not being spent on a major project such as this.

With respect to the requested amounts for this GRC, we note that other large-scale projects are being planned specifically for the Ventura Compressor Station and the Honor Rancho Compressor Station (and the Moreno Compressor station for SDG&E). Because we recognize the importance of the proposed projects and the role of compressor stations in maintaining operational reliability

⁹² Exhibit 32 at MAB/EAM-11.

and safety of the gas transmission system, we find that it is prudent and reasonable to authorize the proposed projects and for SoCalGas to have the necessary funding to conduct these projects (and Moreno Compressor station for SDG&E). At this point, we do not find it necessary to deviate from current GRC practice and authorize funding only for specific projects because of the large scope covered in the GRC and because of the many challenges associated with planning and executing multiple and large projects within a specified timeframe. We do however encourage SoCalGas to place a high priority on critical projects under this category as most of its compressors are over 50 years old and because of key risks that need to be mitigated in this area. Therefore, we find that the requested amounts for Compressor Stations should be authorized.

Regarding Auxiliary Equipment, ORA argues that SoCalGas' spending in prior years is much less, up to more than 50 percent less, than the requested amounts. For its part, SoCalGas states that ORA ignores RAMP-related incremental spending that is planned to address increased risk mitigation efforts of a key risk identified in the RAMP Report.

SoCalGas provided a list of projects under Auxiliary Equipment as well projected costs for each of these and a description of the different projects. The projects include RAMP-related costs such as installation of physical security systems, access controls, and detection capabilities.

However, recorded costs for 2017 of \$5.744 million approximate the five-year average spending for Auxiliary Equipment which is \$5.661 million. Therefore, based on the level of spending for 2017, it would seem that SoCalGas did not perform much of the incremental RAMP-related activities it may have planned which is why recorded costs are around the same level as what it normally spends without the incremental RAMP activities. Therefore, we find

that this is an instance where it is reasonable to rely on 2017 recorded costs. For 2018 and 2019, we assume that SoCalGas will perform the risk mitigation activities it had planned and find that its requested amounts be approved.

To summarize, SoCalGas' requested amounts for Gas Transmission capital expenditures for 2017, 2018, and 2019 should be adopted except for Auxiliary Equipment in 2017 which should be reduced to \$5.744 million representing recorded costs for 2017.

10.2. Cost Recovery for the North-South Project

SoCalGas seeks recovery of costs incurred in conceiving and pursuing the North-South project and according to SoCalGas, undertaking activities in furtherance of the Commission-ordered California Environmental Quality Act (CEQA) review. SoCalGas argues that when it filed Application (A.) 13-12-013 for authority to recover in rates costs associated with the North-South project, the Scoping Memorandum and Ruling issued in that proceeding ordered that a CEQA review be conducted. SoCalGas states that over \$20 million was spent on activities pursuant to the CEQA review during the pendency of the application instead of after the Commission approval of the application, as SoCalGas had originally planned. A.13-12-013 was eventually denied in D.16-07-015 after the Commission found that there were better alternatives to the North-South project. SoCalGas proposes to spread cost recovery evenly for three years resulting in a request to recover \$7.162 million annually from 2019 to 2021. The costs to be recovered are categorized as O&M costs even though this section discusses capital requests.

10.2.1. Positions of Intervenors

ORA, Lancaster, TURN, SCGC, and Sierra Club and UCS oppose any recovery for the North-South project consistent with D.16-07-015. TURN and

SCGC submitted a joint brief arguing that the reasonableness of costs to be recovered were not established, that the costs were incurred during a prior GRC period, that allowing recovery would constitute retroactive ratemaking, that costs were already written off, and that the project was rejected and not abandoned.

10.2.2. Discussion

In D.16-07-015, we rejected the North-South project as well as the proposal to recover project costs in rates.⁹³ The decision did not exclude any costs that may be recovered, such as the application and CEQA costs incurred and we find that pre-construction and pre-engineering costs are included in project costs. Had the application and the proposal to recover project costs been approved, SoCalGas would not have needed to seek separate recovery of CEQA costs. These costs would have been deemed included in what could have been recovered. Thus, when recovery of project costs was denied without any exceptions, the CEQA costs should be deemed part of such costs and denied as well.

According to SoCalGas, the costs to be recovered were incurred prior to May 2014 and after May 2014 up to as late as April 2016, although it does not specify exactly when costs were incurred after May 2014. As noted by TURN and SCGC, this period falls within SoCalGas' previous 2012 GRC. As such, these costs fall outside the period of costs that are being considered and are to be authorized in this GRC proceeding. There is also no memorandum account or

⁹³ D.16-07-015 at 22.

other similar mechanism that set aside consideration of the costs to be recovered such that this issue can be reviewed in this proceeding.

SoCalGas' rebuttal testimony also states that it had planned to conduct CEQA activities after A.13-12-013 had been approved and that in the alternative that the application was denied, that it would not have pursued the CEQA activities.⁹⁴ This shows that SoCalGas already recognized that the application may have been denied and could have addressed recovery for the CEQA costs or a procedure for doing so in A.13-12-013.

Finally, we find that recovery of costs for an abandoned project is different from recovery of costs for a denied project. An abandoned project generally presupposes that the project had been previously authorized or approved which is not the case for a denied project. The Commission definitively concluded in D.16-07-015 that SoCalGas had not demonstrated a need for the proposed North-South pipeline project and that ratepayers not be burdened with any of the costs associated with the project.

In view of all the foregoing, we find that the requested cost recovery for the North-South project of \$7.162 million annually for 2019 to 2021, should be denied.

10.3. SDG&E

SDG&E receives gas from SoCalGas at the San Diego/Riverside County border and through various points of a pipeline that runs along the Orange County and San Diego County coastline.

⁹⁴ Exhibit 32 at MAB/EAM-8

SDG&E's capital expenditures forecast for Gas Transmission is \$10.492 million in 2017, \$10.192 million in 2018, and \$10.042 million in 2019.⁹⁵ SDG&E states that the capital requests are necessary for the safe and reliable operation of SDG&E's gas transmission system. The total forecast is inclusive of FOF benefits of \$0.450 million in 2017 and \$0.150 million in 2018 and RAMP-related costs estimated at \$1.689 million each for 2017, 2018, and 2019. The RAMP-related projects are in connection with mitigation of catastrophic damage involving high-pressure gas pipeline failure identified in the RAMP Report.

10.3.1. Capital Projects

The cost categories and descriptions of the types of projects included in each cost category of SDG&E's capital projects correspond to those described in the SoCalGas portion in sections 10.1.1 to 10.1.6. For SDG&E, we shall only list the categories and provide the capital forecasts for 2017, 2018, and 2019 as follows:

New Pipeline: \$3.901 million each for 2017, 2018, and 2019

Pipeline Replacements: \$1.505 million each for 2017, 2018, and 2019

Pipeline Relocations: \$2,000 each for 2017, 2018, and 2019

Compressor Station: \$4.415 million for 2017, \$4.115 for 2018, and \$3.965 million for 2019

Cathodic Protection: \$0.184 million each for 2017, 2018, and 2019

Meter and Regulator: \$0.485 million each for 2017, 2018, and 2019

SDG&E utilized a base year method for New Pipeline and a five-year average for all of its other capital forecasts. SDG&E does not have an Auxiliary

⁹⁵ The totals in Exhibit 33 were modified by errata corrections in Exhibit 35a.

Equipment category which is discussed in section 10.1.7. of the SoCalGas portion.

10.3.2. Positions of Intervenors

ORA is the only other party that provided comments to SDG&E's capital forecasts. ORA's recommendations which differ from SDG&E's proposals are summarized below:

New Pipeline

\$1.667 million for 2017, \$3.901 million for 2018, and \$0.094 million for 2019. ORA's recommendation is based on using 2017 recorded costs, base year costs for 2018, and a three-year average from 2012 to 2014 for 2019.

Pipeline Replacements

\$0.391 million for 2017, and \$0.588 million each for 2018 and 2019 based on recorded costs in 2017 and deducting costs for the Bear Valley project for 2015 and 2016.

Compressor Station

\$3.432 million for 2017, \$3.605 million for 2018, and \$3.455 million for 2019 based on 2017 recorded costs and removing costs after removing one-time costs associated with security enhancements and the security guard shelter building from the five-year average.

Cathodic Protection

\$0.209 million for 2017 using recorded 2017 costs.

Meter and Regulator

Use 2017 recorded costs for 2017.

10.3.3. Discussion

In reviewing SDG&E's capital forecasts in this section, we first compared SDG&E's forecast methodology versus the various methods applied by ORA.

First, with respect to the use of 2017 recorded costs versus 2017 forecasts, while we do note that recorded results are more accurate and more recent than forecasts covering the same year, selectively applying 2017 recorded costs in some instances but not in others may lead to inconsistent results. The GRC application was filed in 2017 and SDG&E utilized the most recent data available at the time of preparing and filing the application which is base year or 2016 data. As the application progresses, newer data become available, but we find that it is not feasible to constantly update data for the entire application.

Next, we find that for this GRC, updating only select data may lead to inconsistent results as not all data is being updated. For example, a select update in one area resulting in a lower value than the forecast would be inconsistent if another update in a different area would result in a higher value than the forecast but was not applied. For this GRC, it is not practical to update all data as there are vast amounts of data included in the application.

We recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data and we exercise our discretion in doing so in appropriate cases. We will generally not apply select updating of data without any explanation why the updated data should be applied.

From our review of ORA's recommendations, we find that many of the forecast methodologies applied are not consistent or uniform. For example, in New Pipeline, ORA recommends using 2017 recorded costs, base year methodology for 2018, and a three-year average for 2019. ORA also recommended using a three-year average from 2012 to 2014 and not the latest three years.

For recorded costs from previous years, we note that these tend to vary because of large-scale projects that raise costs for a particular year. As such,

ORA recommends eliminating these projects from the five-year average which appears reasonable. However, SDG&E states that it is also planning several large projects under the various cost categories and from our review of prior years, we note that large projects do occur on occasion which results in fluctuating recorded costs. For example, recorded costs for Pipeline Replacements were \$0.081 million in 2012 and \$3.436 million in 2015.⁹⁶ Similarly, for Compressor Station, recorded costs were \$1.878 million in 2012 and \$9.897 million in 2016. SDG&E states that while many of the projects are routine, some projects are difficult to determine in advance. Also, we find that large-scale projects tend to occur on occasion and SDG&E identified some large-scale projects that are being planned for this GRC cycle.

Based on the above, we find that a five-year average is reasonable and appropriate for capturing the fluctuations in recorded costs as well as large-scale projects that occur from time-to-time.

With respect to New Pipeline, SDG&E is recommending use of base year costs as the basis for their forecast. ORA opposes this recommendation and states that recorded costs in 2015 and 2016 were considerably higher because of costs associated with the Pio Pico Energy Center and argues that this is a one-time project and should not be included as a basis for costs in future years. SDG&E argues that it is planning another large-scale project, the Carlsbad Energy Center for 2017 and 2018. However, we find that this project does not extend to 2019 and there was insufficient comparison in costs and scale of the

⁹⁶ Exhibit 35 at MAB/EAM-6

Carlsbad project versus the Pio Pico project. We also find that using base year costs as a basis does not take into account recorded costs in prior years.

Therefore, we find that a five-year average is also more appropriate for New Pipeline similar to the other cost categories where large-scale projects are also being planned for one or more of the years included in this GRC cycle. To summarize, we adopt all of SDG&E's forecast costs for capital expenses for Gas Transmission (including for the authorized amounts for Compressor Stations, discussion in more detail in the SoCalGas Section 10.1.9) except for New Pipeline which should be modified to reflect the five-year average of recorded costs from 2012 to 2016 which is \$2.036.2 million.

11. Gas Major Projects

The SoCalGas Major Projects and Construction organization manages projects associated with pipeline installation, replacement, and modernization. It also includes valves, regulating and metering stations and appurtenances, and other similar projects associated with compressor stations, storage fields, and natural gas fueling stations.

This section addresses RAMP-related risks, particularly, mitigating against catastrophic damage involving medium-pressure pipeline failure identified in the RAMP report.

11.1. O&M

The TY2019 forecast for O&M costs is \$3.971 million which is \$2.713 million more than 2016 adjusted, recorded expenses. O&M costs are divided into three cost categories and all three were forecasted using base year 2016 as a reference. All O&M costs are non-shared and are performed solely for the benefit of SoCalGas. Pursuant to D.16-06-054, costs relating to the Aliso Canyon incident are excluded from the forecast.

11.1.1. Management & Outreach

Management & Outreach is comprised of several cost center groups that relate to general management of staff and associated organizational costs. The cost center grouping includes regulatory and program management personnel that prepare regulatory filings. The forecast for this cost center grouping is \$3.646 million which is \$2.713 million more than base year 2016 adjusted, recorded expenses and is the only O&M category under Gas Major Projects that shows a forecasted change from adjusted 2016 recorded costs.

We reviewed the forecast and find that the reason for the increase is due to expenses associated with four capital projects that have significant assets that will be placed into service in TY2019. Details for the expense elements were provided in Table MAB-12 in Exhibit 50.⁹⁷ In addition, forecasted costs include work of certain employees who were temporarily redirected to perform tasks relating to the Aliso Canyon incident and are now returning to regular duties and responsibilities.⁹⁸

We find the costs to be adequately supported by the evidence presented and have no objections to the forecast for this cost center grouping. ORA and TURN are the only parties that provided comments to the Gas Major Projects section and neither party had any objections to this forecast. The four major projects that were mentioned above are discussed in the capital projects section.

⁹⁷ Exhibit 50 at MAB-10.

⁹⁸ *Id.* at MAB-4.

11.1.2. Project & Construction Management

The forecast for this cost category is \$201,000. This is another cost center grouping and activities to be funded represent functional expertise in performing or assisting in technical development, consultation, planning, permitting, design, material specifications, commissioning, and project management of major infrastructure projects such as large pipelines, compressor stations, valve stations, and interconnect facilities.

There are no adjustments from base year adjusted, recorded expenses for the TY2019 forecast and we find the forecast to be reasonable and adopt it.

11.1.3. Project Controls & Estimating and Gas Contractor Controls

The forecast for this cost category is \$124,000. This is yet another cost center grouping and the activities to be funded relate to activities in support of major capital and some O&M funded projects such as analyzing and developing cost forecasts, cost estimating, schedule development, updating and analysis, managing quality, safety, and compliance of contractors for large projects and project controls utilized by PSEP.

There are also no adjustments from base year adjusted, recorded expenses for the TY2019 forecast and we likewise find the forecast to be reasonable and adopt it.

11.2. Capital

There are three project groupings under this section consisting of four distinct projects. The total forecast for the projects is \$1.2 million in 2017, \$8.969 million in 2018, and \$37.714 million in 2019.

11.2.1. Distribution Operations Control Center

The forecast for the Distributions Operations Control Center (DOCC) is \$400,000 in 2017, \$3.156 million in 2018, and \$25.901 million in 2019 using a

zero-based forecast. The DOCC and related system of field sensors and control assets is a system for monitoring and remotely controlling medium and high-pressure gas distribution pipelines. The system will allow integrated operation of the distribution and existing high-pressure transmission systems and will strengthen SoCalGas' and SDG&E's ability to manage their distribution pipeline operations system in real time. The system also includes remote and automated controls and a constantly staffed facility. The system is proposed to be built in phases from 2017 to 2021 with an estimated total capital cost of \$108 million. This GRC covers costs up to 2019 totaling \$29.457 million.

11.2.2. Pipeline Information Monitoring System

The Pipeline Information Monitoring System (PIMS) is a centralized data system of field sensors and computerized data management assets to monitor conditions external to pipes in real-time along the routes of rights-of-way of large high-pressure gas pipelines. The system will provide early warning, timely response, and mitigation of potential external threats to the physical integrity of pipelines. The forecast for PIMS is \$500,000 for 2017, \$1 million for 2018, and \$7 million for 2019 using a zero-based forecast methodology.

11.2.3. Methane Monitoring & Fiber-Optic Monitoring

These are two separate projects with a combined forecast of \$300,000 for 2017, \$4.813 million each for 2018 and 2019 using a zero-based forecast methodology. The Methane Monitoring project consists of installing 2,100 methane monitoring sensors along pipeline routes where high pressure pipelines that are 12 inches or greater in diameter are located in close vicinity to facilities that are high occupancy, pose logistical evacuation challenges, or have special implications to commerce such as bridges and transportation centers. The Fiber-Optic Monitoring project is for the installation of fiber-optic monitoring

stations. Both systems will report any abnormal activity to the PIMS where it can be viewed and resolved as necessary.

11.2.4. Positions of Intervenors

ORA and TURN are the only other parties to provide comments and recommendations to SoCalGas' capital requests in this section.

ORA recommends using 2017 recorded capital expenditure for all capital projects totaling \$143,000 compared to SoCalGas' forecast of \$1.2 million. TURN, on the other hand, objects to the capital forecast for DOCC for 2019 and recommends \$0. TURN argues that it is not clear that the DOCC will provide meaningful safety benefits to justify the capital costs. TURN adds that real-time monitoring will not significantly improve response times and that most safety incidents are caused by external factors. TURN recommends SoCalGas be instructed to propose the DOCC in its next rate case and be required to quantify benefits, conduct a risk-spend efficiency versus other mitigation measures, and commission a third-party study of PG&E's DOCC facility.⁹⁹

11.2.5. Discussion

In its rebuttal testimony and in briefs, SoCalGas states that it does not oppose ORA's recommendation to use 2017 actual capital expenditures instead of its forecasted amount. While the decision has generally refrained from relying solely on updating only select data to 2017 actual expenses, we recognize that this approach is appropriate in specific instances. The utility has the burden of submitting adequate proof to justify its requests and in this instance, by supporting ORA's position, SoCalGas agrees that it does not have adequate

⁹⁹ Exhibit 490 at 48 to 49.

evidence to substantiate its original request. As a result, we find ORA's recommendation to be the most reliable with respect to this issue and more so because the utility agrees. Therefore, we find it reasonable to adopt ORA's recommendation of approving \$143,000 in 2017 for all four capital projects being proposed under Gas Major Projects.

With respect to TURN's objection to the DOCC, we find that the real-time information and monitoring of gas distribution pipelines that will be provided by the system as described in Exhibit 50 showing the features and other capabilities of the DOCC,¹⁰⁰ provide meaningful safety benefits.

Real-time monitoring and remote-control access to key points in the distribution system allows faster detection of abnormal changes in pressure and speeds up response times to address these issues. SoCalGas also demonstrated that the current system for monitoring pressure in the distribution system is unable to provide continuous monitoring and is unable to monitor multiple units at once making it difficult to triangulate and determine where the actual problem is in the distribution system. SoCalGas also demonstrated significant response time benefits that will be provided by real-time monitoring of abnormally low or high-pressure areas versus the current system even for incidents caused by external factors. Exhibit 55 contains a diagram illustrating an example of how the DOCC can reduce response times.¹⁰¹ As shown in the diagram, detection of a pressure incident as well as analysis of the situation will be significantly improved thereby shortening the potential response time to an incident.

¹⁰⁰ Exhibit 50 at MAB-23.

¹⁰¹ Exhibit 55 at 3.

TURN also argues that real-time monitoring and remote access will not be as effective as SoCalGas suggests since the entire distribution system will not be monitored, and remote-control access will only be available to 200 regulator stations. However, the pressure-monitoring and remote access units to be installed are only for the initial phase of the project and will be installed in key, strategic, and high occupancy areas. All in all, real-time monitoring will be provided for nearly 1,800 high-pressure points and over 4,000 miles of high-pressure pipeline and remote-control access to 200 of the most critical distribution regulator stations.

The system also supports mitigation of a key risk identified during the RAMP process and we find that the real-time monitoring to be provided by the system supports our policy of reducing gas leaks more quickly. We note that we authorized a similar system for PG&E.¹⁰² Finally, we find that postponing the project until the next GRC only serves to delay the project and would likely increase costs. Based on all the above, we find that the requested amounts for the DOCC for 2018 and 2019 should be authorized.

We find that SoCalGas provided sufficient evidence and justification for the necessity of the PIMS and Methane Monitoring and Fiber-Optic Monitoring projects and that these projects will improve safety. We also find the requested amounts in 2018 and 2019 for these projects are reasonable and supported by the evidence.

¹⁰² PG&E's Gas Distribution Control Center was authorized in D.14-08-032 covering its TY2014 GRC application.

Therefore, in view of the foregoing, we find that for capital projects under Gas Major Projects, \$143,000 in 2017, \$8.969 million in 2018, and \$37.714 million in 2019 should be authorized.

12. Gas Engineering

The purpose of Gas Engineering is to establish and oversee the engineering aspects of SoCalGas' and SDG&E's gas infrastructure. Gas Engineering is responsible for complying with federal and state safety and environmental requirements and implementing industry best practices. Gas Engineering also provides technical and engineering support and optimizes infrastructure and end-use equipment performance. Activities relating to land services and rights-of-way (ROW) and research and development also fall under Gas Engineering.

12.1. SoCalGas

The TY2019 forecast for O&M costs is \$26.629 million¹⁰³ which is \$9.406 million more than 2016 adjusted, recorded expenses. SoCalGas' O&M costs include both shared and non-shared services. For capital costs, SoCalGas is requesting \$12.622 million for 2017, \$13.361 million for 2018, and \$14.101 million for 2019.¹⁰⁴ Certain costs are driven by risk mitigation activities pursuant to the RAMP process. The key risks being mitigated in this section are records management, climate change adaptation, and catastrophic damage involving high-pressure pipeline failure. The table below summarizes the estimated costs

¹⁰³ Revised from \$26.629 million to \$26.554 million in the Update Testimony (Exhibit 514) at Attachment H.

¹⁰⁴ SoCalGas revised the forecast from \$12.622 million to \$11.316 million for 2017, \$13.361 million to \$12.484 million for 2018, and \$14.101 million to \$13.224 million for 2019 in the Update Testimony (Exhibit 514) at H.

for the mitigation activities that will be undertaken. These costs are embedded in the O&M and capital costs requested by SoCalGas and the reasonableness of these costs are reviewed in the O&M and capital sections that they appear in.

RAMP Risk	2017	2018	2019
Records Management (O&M)	n/a	n/a	\$5,964,000
Climate Change Adaptation (O&M)	n/a	n/a	\$1,520,000
Catastrophic Damage Involving High-Pressure Pipeline Failure (capital)	\$2,245,000	\$2,245,000	\$2,245,000

Records Management

Gas Engineering provides drafting and design of the gas infrastructure and gas facilities and the material traceability project can help to improve compliance with regulations mandating the maintenance of traceable, verifiable, complete, and readily available documentation.

Climate Change Adaptation

The Geological Hazard Mitigation Program performs analysis and recommendations related to geological, civil, and structural engineering design impacted by weather and climate-driven events.¹⁰⁵

Catastrophic Damage Involving High-Pressure Pipeline Failure

The Engineering Analysis Center provides operations requirements to odorize gas in the gas infrastructure and gas facilities as mandated by the Code

¹⁰⁵ Exhibit 60 at DRH-10.

of Federal Regulations 192 Subpart I. The requested costs relate to “odorization”¹⁰⁶ equipment and techniques for pipeline systems.

This section also includes \$55,000 in O&M savings from FOF which has been incorporated into the forecast. Costs relating to the Aliso Canyon gas leak incident are excluded from the forecast and from historical costs.

12.1.1. Non-Shared O&M

The total forecast for non-shared costs is \$12.226 million which is \$4.440 million higher than 2016 costs. Non-shared O&M cost categories are composed of Gas Engineering and Land Services & Right-of-Way. The table below shows the forecast for each cost category.

Non-shared O&M	2019	Change from 2016
Gas Engineering	\$8,600,000	\$2,920,000
Lands Services & Right-of-Way	\$3,626,000	\$1,520,000
Total	\$12,226,000	\$4,440,000

12.1.1.1. Gas Engineering

Costs include activities associated with the following departments:

- (a) Engineering Analysis Center (EAC);
- (b) Measurement, Regulation, and Control (MRC);
- and (c) Civil, Structural, and Hazard Mitigation Engineering.

The EAC and MRC departments perform core engineering activities to maintain safe and reliable operations and support to various organizations within SoCalGas. These include oversight and administration, air quality and compressor services, applied technologies, and field support. The forecast for

¹⁰⁶ Natural gas odorization equipment are classified as either chemical vaporization or chemical injection equipment.

the EAC and MRC departments utilized a five-year average because it better accounts for the work that ebbs and flows over time.

Meanwhile, Civil, Structural, and Hazard Mitigation Engineering activities include ongoing structural engineering design and new hazard mitigation programs which include geological hazards and climate change risk mitigations. Costs for these were forecast using the base year method with incremental costs added reflecting costs for new or enhanced programs such as satellite monitoring.

12.1.1.2. Land Services & Right-of-Way

Costs under this category relate to general expenditures to manage the necessary property rights to allow access, operation, and maintenance of pipeline infrastructure which traverses over both public and private land and properties. The five-year linear method was utilized to forecast these costs because activities and staffing levels have been steadily increasing and SoCalGas expects this trend to continue.

In addition to these costs, SoCalGas is requesting the creation of the Morongo Rights-of-Way Memorandum Account (MROWMA) and the Morongo Rights-of-Way Balancing Account (MROWBA) in connection with four expired and expiring rights-of-way impacting existing gas transmission pipelines and a gas distribution center located in the Morongo Indian Reservation (Reservation).

The MROWMA will record pre-construction costs associated with the possible relocation of gas transmission pipelines to bypass the Reservation as described in A.16-12-011 where it made the same request. On the other hand, the MROWBA will record costs associated with the renewal of the expiring ROWs described above as well as pre-construction costs associated with potential relocations that will be incurred beginning January 1, 2019.

12.1.1.3. Positions of Intervenors

ORA and TURN provided comments to the non-shared O&M requests.

ORA does not object to the Gas Engineering forecast but recommends a year-on-year increase of 9.6 percent based on the increase of costs from 2016 to 2017. This results in a reduction of \$0.854 million from SoCalGas' forecast. ORA also recommends the establishment of a MROWMA that will track all costs relating to the expiring ROWs with recovery of costs being subject to a reasonableness review.

TURN recommends that the Commission deny both the request to establish a MROWMA and MROWBA. TURN argues that costs to be tracked by the MROWMA are already included in SoCalGas' TY2016 GRC and that the pre-construction costs to be tracked by the MROWBA may be included in Gas Transmission and Major Projects or can be recorded through working cash and construction work in progress (CWIP). TURN also recommends disallowance of \$877 in costs relating to expenses for clothing and gear that does not contain SoCalGas' logo.

12.1.1.4. Discussion

SoCalGas objects to ORA's proposal of applying a year-on-year growth of 9.6 percent to 2017 recorded costs and states that this does not take into account historical costs and other cost drivers such as governmental fees and a project to deploy a ROW database. SoCalGas also argues that there is an upward trend with regards to costs.

We reviewed both methodologies and find that ORA's method relies heavily on 2017 recorded costs which is less than SoCalGas' 2017 forecast by \$0.398 million. ORA then applies the increase rate between 2016 and 2017 to 2018 and then to 2019. We find that this method does not take into account prior

years where increases were 209.0 percent (from 2013 to 2014) and 22.4 percent (from 2014 to 2015).¹⁰⁷ We agree with SoCalGas that projected costs are hard to predict since the ROW costs are based on contractual agreements and the perceived value of the ROW access points which are often subject to change. Thus, we find that reliance on a longer period of historical costs is more appropriate and find that SoCalGas' forecast of \$3.626 million for Land Services and Right-of-Way is more reasonable and should be approved.

With regards to TURN's objection to \$877 spent on clothing and gear, we find that a nominal amount spent on such promotional materials¹⁰⁸ is reasonable.

Based on the above, we find it reasonable to authorize SoCalGas' total non-shared services forecast of \$12.226 million.

MROWMA and MROWBA

SoCalGas operates three gas transmission pipelines (Lines 2000, 2001, and 5000) that cross the Reservation and a gas distribution system located in the Reservation that serves the residential and commercial needs of the Morongo Band of Indians (Morongo). SoCalGas' operation of the above are pursuant to four existing ROWs granted by the federal government through the Bureau of Indian Affairs (BIA). The first ROW was granted by the BIA in 1948 with the rest being granted at different times subsequently. The four ROWs have been renewed at various points in time but are currently set to expire as follows:

Line 2000 – expires on March 29, 2018

Line 5000 – expires on August 21, 2018

¹⁰⁷ Exhibit 63 at DRH-8, Table 13-12.

¹⁰⁸ The type of clothing and gear discussed are often used as promotional items during informational, educational, or other events conducted by SoCalGas.

Gas Distribution System – expires on August 21, 2018

Line 2001 – expires on March 22, 2020

The three gas transmission pipelines are part of SoCalGas' Southern System and transport gas received from interstate pipelines. The Southern Transmission System has a receipt point capacity of about 1.2 billion cubic feet per day which represents approximately 26 percent of the total system receipt point capacity. The three gas transmission pipelines are necessary in providing service to SoCalGas' customers (including Morongo) as well as the SDG&E gas delivery system and for maintaining system reliability.

Appraisals to determine the appropriate valuation of the ROWs were completed in February 2015 and SoCalGas has been negotiating with Morongo for the renewal of the four ROWs since July 2015, when it submitted a formal offer to Morongo for a 50-year renewal. However, negotiations for renewal of the ROWs have not progressed up to the time the GRC application was filed and SoCalGas states that it has to consider potential relocation of the three transmission lines outside of the Reservation.

With respect to the costs to be tracked in the MROWMA, SoCalGas states that the costs to be tracked are the same pre-construction costs described in A.16-12-011 and it makes the same request here because parties in A.16-12-011 argued that these costs should be recovered in the GRC. At the time this GRC was filed, A.16-12-011 was still pending. The proceeding was resolved in D.18-04-012¹⁰⁹ wherein the Commission denied SoCalGas' request, the dispositive portion of which states:

¹⁰⁹ The decision was dated April 26, 2018.

“We have reviewed the positions and arguments that parties have raised and examined the testimonies and other exhibits submitted and based on our review, we find that the pre-construction costs to be tracked by the memorandum account are GRC-costs that should have been raised and are therefore deemed included in SoCalGas’ 2016 GRC. SoCalGas argues that these costs were not ripe for inclusion in the 2016 GRC but does not argue or provide evidence that it was prohibited, precluded, or otherwise incapable of including these costs in its 2016 GRC, specifically, in the capital expenditures for gas transmission and engineering. It is also clear that SoCalGas was well aware that the first three ROWS were set to expire during the period covered by the 2016 GRC. SoCalGas made a formal offer to Morongo on July 2015 while the 2016 GRC was still pending but did not make an argument as to what would have been a reasonable time within which to expect a reply from Morongo. Absent any such showing, we find that Morongo’s non-response after several months is sufficient time as to alert SoCalGas to the possibility that its offer would not be accepted and that it would have to consider other options and that these events were not unforeseeable.

Moreover, the Settlement Agreement adopted in D.16-06-054 states that it sets forth a complete and final resolution of all revenue-requirement related issues in the 2016 GRC proceeding. As pointed out by TURN and SCGC, Exhibit B of the Settlement Agreement sets out the specific revenue requirement amounts proposed for various areas of SoCalGas’ operations with page B-3 covering shared and non-shared gas transmission expenses, and pages B-6 to B-7 addressing the capital expenditures for the gas transmission system. SoCalGas argues that costs relating to the Morongo ROW renewals were not subject to the settlement, nor were they explicitly identified in the 2016 GRC. However, as SoCalGas admits, its 2016 GRC testimony did not include categories for a number of specific projects, including the new “Major Projects” organization, but rather presented a general forecast covering whatever projects would arise for the entire transmission organization. SoCalGas also does not provide any evidence demonstrating that parties were aware that the Morongo ROW renewals would be treated separately from the Settlement

Agreement. Absent such showing, we find it reasonable to assume that parties to the settlement had no knowledge of any such exclusions or additional costs and projects, covering pre-construction costs that are consistent with the categories of costs that SoCalGas identified in its 2016 GRC. Thus, parties had every reason to assume that the revenue requirement determined in the Settlement Agreement addressed all revenue requirement costs within the 2016 GRC period.”¹¹⁰

The findings and conclusions made in D.18-04-012 are applicable here with respect to pre-construction costs prior to periods covered in this GRC as these costs are deemed included in SoCalGas’ T2016 GRC. However, the same principle does not apply with respect to pre-construction costs for periods that are covered in the TY2019 GRC.

As of the date of this decision, negotiations to renew the ROWs are still ongoing and an agreement can still be reached regarding renewal of the expired ROWs. However, in light of the important role these pipelines provide to system reliability and because renewal of the ROWs remains uncertain, we find that costs associated with considering alternatives to renewing the ROWs are necessary and appropriate. In addition, SoCalGas specifically excluded such costs from its TY2019 forecast and we agree that the costs are difficult to predict. Therefore, we find that SoCalGas’ requests to establish the MROWMA should be authorized.

With respect to the MROWBA, the costs are specifically excluded from any of SoCalGas’ forecasts in this GRC and we also agree that the costs are difficult to predict. Thus, we disagree with TURN’s proposal to include these costs in Gas

¹¹⁰ D.18-04-012 at 10 to 12.

Transmission and Major Projects. We also have no objections for the costs to be tracked. However, we agree with ORA that the costs should be tracked in a memorandum account as opposed to a balancing account to allow the Commission the opportunity to conduct a reasonableness review of the costs to be recovered. The testimony submitted in the proceeding does not include sufficient details as to the activities to be performed or the costs that will be incurred and whether these are necessary and reasonable. In addition, negotiations regarding renewal of the ROWs are still ongoing and an agreement may still be reached and so the activities to be performed are uncertain. Thus, we find it more appropriate for these costs to be tracked in a memorandum account where the Commission will be afforded an opportunity to review the costs incurred.

We therefore find it reasonable to deny the requested authority to establish the MROWBA. Instead, the costs that are being requested to be recorded in the proposed MROWBA should be tracked in the MROWMA being authorized in this decision. Recovery of the tracked costs may then be requested by SoCalGas in its next GRC proceeding which the Commission can then review for reasonableness thereof. In its next GRC filing, SoCalGas should include testimony confirming any costs associated with Morongo ROW negotiations and/or resolution if an agreement is reached.

12.1.2. Shared O&M

The total forecast for shared services costs is \$14.403 million¹¹¹ which is \$4.966 million higher than 2016 costs. The table below shows the forecast for each shared services cost category.

Shared O&M	2019	Change from 2016
Director of Gas Engineering	\$808,000	\$421,000
Measurement, Regulation, and Control	\$6,648,000	\$1,718,000
Engineering Design	\$4,376,000	\$2,248,000
Engineering Analysis Center	\$2,133,000 ¹¹²	\$632,000
Gas Operations Research and Materials	\$438,000	-\$53,000
Total	\$14,403,000	\$4,966,000

12.1.2.1. Director of Gas Engineering

This cost category includes expenditures incurred for the director of Gas Engineering as well as administrative and support functions. SoCalGas utilized a five-year average methodology in developing its forecast.

12.1.2.2. MRC

The MRC shared cost centers are for engineering policy, design, material selection, testing and field support related to measurement, gas regulation, automated control systems for pipelines, compressor stations, and other instrumentations.¹¹³ The forecasts for MRC were developed utilizing a five-year average methodology.

¹¹¹ Revised from \$14.403 million to \$14.329 million in the Update Testimony (Exhibit 514) at Attachment H.

¹¹² Revised from \$2.133 million to \$2.059 million in the Update Testimony (Exhibit 514) at Attachment H.

¹¹³ Exhibit 60 at DRH-24.

12.1.2.3. Engineering Design

The Engineering Design cost centers are for engineering policy and design for both SoCalGas and SDG&E. This includes design drafting, process engineering, pipeline engineering, mechanical design, electrical design, and high pressure and distribution engineering network design. Costs were forecast utilizing a five-year average methodology, except for electrical engineering design wherein a base year method was utilized because new activities were included and high pressure and distribution engineering network design (HPDEND) which utilized a five-year linear method because activities and staffing levels have been consistently rising and this trend is expected to continue.

12.1.2.4. Engineering Analysis Center

The Engineering Analysis Center provides related environmental, gas operation, and other testing that help verify that safe pipeline quality gas is delivered. The forecast was developed using a five-year average.

12.1.2.5. Gas Operations Research and Materials

The cost centers included in this cost category manage the related business processes for approval, documentation, and quality management of gas pipelines and appurtenance materials and ensures compliance with regulatory requirements that mandate minimum requirements for the selection and qualification of pipes and components used in pipes. The group also provides support regarding information related to materials as well as management and coordination of research and development programs related to the environment. Costs were forecast utilizing a base year method because this cost center was shifted from another cost center rendering historical data unusable.

12.1.2.6. Position of Intervenors

Only ORA provided comments to the shared services O&M forecast. ORA recommends using 2017 costs of \$0.502 million for HPDEND instead of a five-year linear method. ORA also recommends a \$75,000 reduction to Engineering Analysis Center after it was discovered through a data request that an incremental FTE for a management position is not being requested.

12.1.2.7. Discussion

SoCalGas agrees with ORA's proposed reduction of \$75,000 to Engineering Analysis Center because the corresponding FTE to be funded by said amount is not being requested. SoCalGas removed the amount in Update Testimony (Exhibit 514) at H-1. With respect to the forecast method for HPDEND, SoCalGas argues that a five-year linear method is appropriate because costs have been increasing. However, ORA provided a graph showing HPDEND expenses from 2012 to 2017.¹¹⁴ The graph shows that costs decreased from \$0.513 million to \$0.488 million and then to \$0.486 million in 2013, 2014, and 2015 respectively. Costs decreased again in 2016 from \$0.544 million to \$0.502 million in 2017. From the above, it is clear that costs have not been increasing with consistency. Therefore, we find ORA's forecast to be more appropriate which reduces the forecast for Engineering Design by \$0.148 million.

We reviewed the rest of the shared services forecast and do not disagree with the use of five-year averages to develop these forecasts and a base year method because of the shift in cost center which renders historical data unusable for Gas Operations Research and Materials. Therefore, we find that SoCalGas

¹¹⁴ Exhibit 408 at 23.

shared services forecasts should be adopted except for a reduction of \$148,000 to Engineering Design.

12.1.3. Capital

As stated previously, SoCalGas' capital forecast is \$12.622 million for 2017, \$13.361 million for 2018, and \$14.101 million for 2019. The table below provides a breakdown of the requested capital costs.

Capital	2017	2018	2019
Land and Right-of-Way ¹¹⁵	\$5,468,000	\$5,468,000	\$5,468,000
Capital Tools & Lab Equipment ¹¹⁶	\$2,245,000	\$2,245,000	\$2,245,000
Supervision & Engineering Overheads	\$4,909,000	\$5,648,000	\$6,388,000
Total	\$12,622,000	\$13,361,000	\$14,101,000

12.1.3.1. Land and Right-of-Way

The forecast will fund purchase of land or land rights for new high-pressure pipelines and for existing ROWs that have expired relating to pipelines that are installed on private lands. SoCalGas utilized a five-year average methodology to develop its forecast.

12.1.3.2. Capital Tools & Lab Equipment

This forecast is for acquiring and replacing high-value tools that are used daily by operating personnel such as volt/amp meters, Global Positioning System receivers, etc. This also includes laboratory equipment used for the EAC. A five-year average was used to develop the forecast.

¹¹⁵ SoCalGas revised the forecast for Land and Right-of-Way from \$5.468 million to \$3.892 million for 2017, \$5.468 million to \$4.591 million each for 2018 and 2019 in the Update Testimony (Exhibit 514) at Attachment H.

¹¹⁶ SoCalGas revised the forecast for Capital Tools & Lab Equipment from \$2.245 million to \$2.515 million for 2017 in the Update Testimony (Exhibit 514) at Attachment H.

12.1.3.3. Supervision & Engineering Overheads

This cost category is for transportation and storage supervision and engineering overhead charges which are later on assigned to other areas. A five-year linear average was utilized because costs have been steadily increasing due to the increasing complexity of planning and engineering gas capital projects.

12.1.3.4. Positions of Intervenors

ORA is the only other party that provided comments to SoCalGas' capital requests. ORA does not object to the forecast for Capital Tools & Lab Equipment but recommends using 2017 recorded costs resulting in an increase of \$0.270 million to the 2017 forecast.

For Land and Right-of-Way, ORA recommends using an average of 2016 and 2017 recorded costs for the 2017 forecast and then using the result as the basis for the 2018 and 2019 forecasts. This results in reductions of \$1.576 million in 2017 and \$0.788 million each for 2018 and 2019.¹¹⁷

For Supervision and Engineering Overheads, ORA recommends applying a year-on-year growth of 8.43 percent which represents the increase from 2016 to 2017.

12.1.3.5. Discussion

SoCalGas states that Morongo-related expenses were excluded from 2017 recorded costs which formed a large part of the basis for ORA's calculations. And as stated above, an agreement regarding renewal of the ROWs may still be achieved and so it is uncertain whether costs incurred will relate to ROW

¹¹⁷ This reduction is reflected in SoCalGas' Update Testimony (Exhibit 514) at Attachment H.

renewal or construction around the Reservation. Given the uncertainty of the negotiations and the speculative nature of potential construction costs, we find that Morongo-related costs should first be tracked instead of approved, so the Commission has the opportunity to review associated costs. As a result, we find ORA's forecasts for Land Services to be more accurate as it excludes Morongo-related costs.

Based on the above, for Land Services, we find that \$3.892 million for 2017, \$4.591 million for 2018, and \$4.591 million for 2019 should be authorized. While we are denying SoCalGas' request to establish the MROWBA, we find SoCalGas' request to create a Memorandum Account is reasonable and allows all Morongo-related costs incurred beginning January 1, 2019 to be recorded subject to a reasonableness review in SoCalGas' next GRC filing.

We find the forecast for Capital Tools & Lab Equipment to be reasonable and agree with the five-year average methodology that was utilized in developing the forecast. We disagree with using 2017 recorded costs consistent with not favoring select updating of 2016 data as applied throughout the decision unless there is good reason to do so in appropriate instances.

For Supervision and Engineering Overheads, we find SoCalGas' methodology more appropriate as it takes into account historical trends as opposed to ORA's method which relies heavily on 2017 costs. In this instance, we find that taking into consideration costs and trends from a wider period of time provides a better gauge of the fluctuating costs for this group.

Based on the above, we find that capital projects under Gas Engineering should be authorized as follows: \$11.046 million for 2017, \$12.484 million for 2018, and \$13.224 million for 2019 which excludes Morongo-related costs.

12.2. SDG&E

SDG&E's Gas Distribution and Transmission system is comprised of approximately 225 miles of transmission pipeline and 15,000 miles of mains and service lines.¹¹⁸ SDG&E receives gas from SoCalGas through several interconnections between the two systems.

SDG&E's capital request for Gas Engineering is \$0.268 million¹¹⁹ each for 2017, 2018, and 2019. SDG&E's O&M costs are captured in the shared services forecasts of SoCalGas. The table below provides a breakdown of the requested capital costs.

Capital	2017¹²⁰	2018	2019
Land and Right-of-Way	\$113,000	\$113,000	\$113,000
Auxiliary Equipment	\$28,000	\$28,000	\$28,000
Capital Tools	\$54,000	\$54,000	\$54,000
Supervision & Engineering Overheads	\$73,000	\$73,000	\$73,000
Total	\$268,000	\$268,000	\$268,000

Land and Right-of-Way

Costs for the purchase or renewal of easements and acquisition of ROWs for installing and maintaining high pressure pipelines. Costs were forecast using a zero-based method for labor and a five-year average for non-labor

¹¹⁸ Exhibit 64 at DRH-2.

¹¹⁹ Revised 2017 forecast from \$0.268 million to \$0.889 million in the Update Testimony (Exhibit 514) at Attachment I.

¹²⁰ The following 2017 capital forecasts were revised to the following amounts in the Update Testimony (Exhibit 514) at Attachment I: Land and Right-of-Way \$0.488 million, Auxiliary Equipment \$0.295 million, Capital Tools \$0.106 million, Supervision & Engineering Overheads \$0 million.

Auxiliary Equipment

Costs for purchase of auxiliary equipment to support compressor stations. Costs were forecast using a combination of base year for items that have no historical costs prior to 2015 and a five-year average for other items.

Capital Tools

Costs for acquiring and replacing high-value tools routinely used by operating personnel. Costs were forecast using a five-year average.

Supervision & Engineering Overheads

Costs for supervision and engineering overhead charges which are later on assigned to other areas. Costs were forecast using a five-year average.

12.2.1. Positions of Intervenors

ORA is the only party that provided comments and recommends using 2017 recorded costs except for Supervision and Engineering Overheads where it recommends zero dollars. ORA's recommendation results in a 2017 total of \$0.889 million. SDG&E agrees with ORA's recommendation.

12.2.2. Discussion

As applied consistently throughout this decision, we have not favored select updating of 2016 data utilized throughout the GRC to 2017 recorded costs unless it is justified and there is good reason to do so as it is not feasible to update all the data and updating only select data may lead to inconsistencies. In addition, SDG&E's testimony only provides support for its forecast and not regarding the reasonableness of the higher amount.

In this case, we reviewed SDG&E's capital forecasts and find them to be reasonable and supported by the evidence presented. We also find the costs to be necessary and agree with the forecast methodologies that were utilized. Thus,

we find that SDG&E's capital requests for Gas Engineering of \$0.268 million each for 2017, 2018, and 2019 should be approved.

13. Underground Storage

The forecasts for Underground Gas Storage (UGS) discussed in this section also address O&M and capital costs for three other functional areas which are Aboveground Gas Storage (AGS), the Storage Integrity Management Program (SIMP), and Storage Risk Management (SRM).

AGS concerns the storage field assets that are aboveground which include compressors, pipelines, purification, and auxiliary equipment. UGS concerns the storage reservoir and storage field wells and includes operation, maintenance, integrity, and engineering functions associated with use of these facilities. SIMP is an integrity management program for inspection and risk management of SoCalGas' storage fields. Lastly, SRM includes aboveground monitoring, data management, compliance, and audit support.

According to SoCalGas, gas storage fields require continuous installation, maintenance, refurbishment, and replacement of heavy industrial equipment such as engines, compressors, electrical systems, wells, piping, gas processing components, and instrumentation.¹²¹ SoCalGas operates four underground storage fields: Aliso Canyon, La Goleta, Honor Rancho, and Playa del Rey. Natural gas is compressed onsite and injected into the field reservoirs through piping networks and storage wells. Storage gas is then withdrawn and delivered through the transmission and distribution system when customer demand exceeds flowing gas supplies.

¹²¹ Exhibit 273 at NPN-2.

Certain costs are associated with mitigating key risks identified in the RAMP Report. The risks that are being mitigated by various activities are catastrophic damage involving high-pressure pipeline failure, physical security of critical gas infrastructure, climate change adaptation, and catastrophic event related to storage well integrity. Exhibit 273 contains a description of how SoCalGas evaluated these risks in the RAMP Report.¹²² The RAMP risks were discussed in the RAMP report. Total expenditure relating to RAMP will be identified in both the O&M and capital sections of the discussion.

Also, in compliance with D.16-06-054, costs relating to the Aliso Canyon leak incident have been removed from historical costs and information used by SoCalGas' witnesses.

Compliance with regulations from the Division of Oil, Gas, and Geothermal Resources (DOGGR), U.S. Department of Transportation (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA), SB 887, and the California Air Resources Board (CARB) impact the forecasts in this section.

13.1. O&M

The total forecast for O&M costs for TY2019 is \$60.074 million which is \$13.766 million more than 2016 adjusted, recorded expenses. This is inclusive of FOF savings of \$0.327 million. RAMP-related costs totaling \$6.859 million are included in the forecasts.

¹²² Exhibit 273 at NPN-10 to 17.

13.1.1. Non-Shared Costs

13.1.1.1. UGS and AGS

The forecast for UGS and AGS is \$38.699 million which is \$5.376 higher than base year adjusted, recorded expenses using a five-year average for labor and base-year plus incremental costs for non-labor.

The functions of UGS and AGS were described briefly at the beginning of this section. SoCalGas' integrated transmission pipeline and distribution system enables delivery of natural gas either to customers or into the storage field reservoirs depending on demands to the system. The individual storage facilities either receive gas or provide gas through injections or withdrawals. Demand for natural gas is subject to heavy fluctuations so injections and/or withdrawals of natural gas may be required at any hour and the storage fields are continuously staffed with operating crew and personnel.

Increased costs forecast for TY2019 are driven by pipeline integrity inspection requirements, increase in regulatory fees, special leak surveys, ambient air monitoring costs and other new operating requirements required by new legislation and new regulations.

13.1.1.2. Storage Risk Management

The TY2019 forecast for SRM costs is \$2.031 million compared to base year adjusted, recorded expenses of \$0.479 million. SoCalGas utilized a base year plus incremental costs in developing its forecast. Incremental costs are to address additional regulations from CARB, DOGGR, and PHMSA.

13.1.1.3. SIMP

The forecast for SIMP is \$18.910 million which is \$6.859 million higher than 2016 adjusted, recorded costs using a zero-based forecast methodology. As stated in the opening portion of this section, SIMP is an integrity management program for inspection and risk management of SoCalGas' storage fields. O&M

activities consist of physical well inspection, risk management, and data management of the UGS program. SoCalGas uses state-of-the-art inspection technologies to conduct inspections.

For the TY2016 GRC, SIMP costs were recorded and balanced in the SIMP Balancing Account (SIMPBA) and SoCalGas is requesting continued approval of the regulatory treatment of costs recorded in the SIMPBA. According to SoCalGas, increased O&M costs are driven by new regulatory requirements leading to increases in costs for personnel, well inspections, UGS regulatory implementation, data management, noise and temperature logs, and emerging regulations.

13.1.2. Shared Costs

Shared Costs consists of activities performed by the Senior Vice President group for Transmission and Storage. The forecast for TY2019 is \$0.434 million using base year costs as a basis. Activities here provide leadership and guidance for various organizations including Underground Storage.

Most, and possibly all, of the costs here may be subject to the revisions to Pub. Util. Code § 706 brought about by SB 901 disallowing ratepayer recovery of officer compensation which became effective January 1, 2019. Treatment of the portion of costs comprising officer compensation is discussed in section 4.2. of the decision.

13.1.3. Positions of Intervenors

ORA and OSA provided comments regarding this section.

ORA does not oppose any of the O&M forecasts by SoCalGas but recommends the creation of a one-way balancing account to record routine costs for UGS and AGS in order to protect ratepayers from costs from new regulatory

requirements. ORA also recommends that the SIMPBA be approved as a one-way balancing account.

OSA recommends that SoCalGas develop a safety management system (SMS) framework to address gas storage assets and operations and present its proposal in the next GRC.

13.1.4. Discussion

We reviewed the evidence submitted as well as arguments raised in briefs and find the TY2019 forecasts for O&M costs to be reasonable. Although there is a considerable increase from 2016 adjusted, recorded costs, SoCalGas sufficiently set forth that majority of the cost drivers for the increase are a result of new laws, regulations, and requirements from CARB, DOGGR, and PHMSA among others, requiring additional inspections, testing, leak surveys, reporting, data management, and other requirements. We also find the various forecasts utilized to be appropriate and note that parties did not object to any of the O&M forecasts.

Regarding ORA's two recommendations concerning balancing accounts, first, we find that the creation of a one-way balancing account to record routine costs for UGS and AGS is not necessary at this time. ORA's concern is to protect ratepayers from costs resulting from new regulatory requirements. However, as SoCalGas explained, the TY2019 forecast for routine UGS and AGS costs were developed to address routine costs that are regularly performed and regulatory requirements that are already in effect, are measurable, and not widely variable. In addition, two new regulations being proposed by DOGGR to replace existing regulation are not expected to materially alter forecast costs. The proposed regulations will affect routine activities such as training, pressure and subsurface leak surveys, patrolling field lines, maintaining records, monitoring and

inspection, safety precautions, and other activities that are deemed routine. SoCalGas has also examined the drafts for the proposed legislation and did not find a proposed provision that would materially affect the compliance activities that they are already required to conduct.

With regards to whether the SIMPBA should be approved as a one-way or two-way balancing account, ORA states that a one-way balancing account encourages SoCalGas to spend within the amount authorized and that it has adequate experience to determine inspection, repair, and other costs associated with SIMP. On the other hand, SoCalGas states that SIMP-related work is variable and regulations affecting SIMP are dynamic and subject to changes which makes the costs variable. For example, SoCalGas states that more frequent well inspections, use of new techniques and tools, and additional data collection are being or may be proposed.

We weighed the arguments raised by both parties and find the issues raised by SoCalGas are of more concern with respect to regulatory treatment of the SIMPBA. As demonstrated by SoCalGas in Exhibit 276, work relating to the SIMP may vary greatly and SoCalGas provided several examples, such as proposed regulations that may have a significant impact on costs.¹²³ A two-way balancing account gives SoCalGas sufficient flexibility to address these possible variances and at the same time allows unspent funds to be returned to ratepayers. With respect to ORA's concern about protecting ratepayers and encouraging SoCalGas to spend prudently, the current version of the SIMPBA authorized in D.16-06-054 requires the filing of a Tier 3 advice letter to recover

¹²³ Exhibit 276 at NPN-11 to 13.

any undercollection up to 35 percent and the filing of an application to recover undercollections greater than 35 percent.¹²⁴ This affords the Commission an opportunity to review any requests to recover undercollections.

Based on the above, we find it reasonable to authorize the SIMPBA and to continue the balancing account treatment established in D.16-06-054 as described above. The SIMPBA shall continue to be maintained as a two-way balancing account subject to the same recovery procedure established in D.16-06-054 for any undercollections from the authorized amount. Any unused funds are to be returned to ratepayers.

Regarding OSA's recommendation for a SMS framework, SoCalGas agrees with OSA regarding the development of a SMS framework to address gas storage assets and operations. SoCalGas states that it is committed to voluntary implementation of the API RP 1173¹²⁵ concerning pipeline safety management system requirements. The RP provides guidance to pipeline operators for developing and maintaining a pipeline SMS to manage the safety of complex processes. We agree with OSA that implementing a SMS framework may be beneficial and also agree that SoCalGas should include a SMS proposal for gas storage in its next GRC application.

13.2. Capital

The forecast for capital costs is \$208.535 million in 2017, \$180.646 million in 2018, and \$172.606 in 2019. RAMP-related activities totaling \$134.870 million in 2017, \$120.495 million in 2018, and \$111.601 million in 2019 are included in the

¹²⁴ D.16-06-054 at 249 to 250.

¹²⁵ Exhibit 276 at NPN-15.

forecasts. The proposed capital expenditures are to enable the safe and reliable delivery of natural gas to customers, enhance integrity, efficiency, and responsiveness of operations, and comply with regulations including environmental regulations.

ORA is the only other party that provided comments and recommendations to the UGS capital expenditures. Because ORA's comments are similar in nature, they are included in the description for each project group. Discussion of all project groups including ORA's recommendations are combined to avoid repetitive analysis and discussion of similar issues.

13.2.1. Storage Compressors

Storage compressors increase the pressure of natural gas so it can be injected into the underground reservoirs. The capital projects in this section are associated with SoCalGas' natural gas compressors. The table below shows the estimated costs for 2017, 2018, and 2019.

Compressors	2017	2018	2019
Goleta – main unit #4 overhaul and heater addition	\$2,000,000	\$326,000	\$0
Honor Ranch – compressor replacement study	\$1,000,000	\$3,000,000	\$10,000,000
Playa Del Rey – wet gas compressor	\$1,000,000	\$1,000,000	\$0
Compressor Blanket Projects	\$5,000,000	\$12,170,000	\$15,700,000
Total	\$9,000,000	\$16,496,000	\$25,700,000

The Unit #4 compressor at Goleta has reached the maximum run time between overhauls and SoCalGas plans to overhaul and restore Unit #4. SoCalGas also plans to add an engine oil heater to reduce the operational wear and tear on internal components. The forecast utilized was developed using the knowledge of experienced personnel who handled similar overhauls and oil heater installations.

The Honor Ranch project is for a feasibility study to replace five compressors and enterprise high-speed reciprocating engines. SoCalGas states that the compressors have reached the end of their useful life after approximately forty years of service. The forecast method utilized is zero-based.

The Playa Del Rey project is to build and place in service a wet gas¹²⁶ compressor. The forecast was developed using similar projects completed in recent years.

Blanket Projects consist of various smaller projects with individual cost estimates to replace and upgrade compressor equipment. The forecast was developed using knowledge of managers at storage fields.

ORA does not object to the 2018 and 2019 forecasts but recommends adopting 2017 adjusted, recorded expenses of \$5.683 million instead of the 2017 forecast.

13.2.2. Storage Wells

The next set of projects is associated with storage wells. Projects are for the replacement of components, and design and drilling of replacement wells for the injection and withdrawal of natural gas and reservoir observation.

¹²⁶ Wet gas is natural gas that contains more than 0.1 gallons of condensable elements per 1,000 cubic feet of gas.

Storage Wells	2017	2018	2019
Replacements	\$4,000,000	\$18,000,000	\$49,000,000
Plug & Abandon	\$38,900,000	\$23,150,000	\$7,250,000
Tubing Upsizing	\$2,680,000	\$1,050,000	\$0
Workovers	\$11,969,000	\$5,369,000	\$969,000
Wellhead Repairs & Replacements	\$1,036,000	\$556,000	\$0
Recompletions	\$0	\$0	\$0
Blanket Projects	\$1,000,000	\$1,000,000	\$1,000,000
Cushion Gas Purchase	\$0	\$0	\$2,340,000
Total	\$59,585,000	\$49,125,000	\$60,559,000

There are approximately 57 to 65 wells that are planned for abandonment. Replacement storage wells will be drilled to replace abandoned wells. The forecast for replacements and plugging and abandoning wells vary in cost, but the average replacement cost is \$7 million per well and \$0.850 million for each abandonment.

SoCalGas also plans to redesign wells to improve tubing flow to increase injection and withdrawal capacity and to create a dual barrier for safety. Well workovers are maintenance activities to prevent fluid encroachment and maintain withdrawal and injection capacity. SoCalGas also plans to replace or repair wellhead valves and seals on various wells to maintain equipment integrity. All of these projects were forecast utilizing a zero-based method.

Blanket projects consisting of multiple smaller projects were forecast using experienced professionals. Finally, SoCalGas plans to purchase cushion gas¹²⁷ to support the final phase of the Honor Rancho expansion project. Costs are estimated at \$2.74 to \$2.91 per decatherm.

¹²⁷ The minimum volume of gas required in an underground storage reservoir to provide the necessary pressure to deliver working gas volumes to customers.

ORA does not object to the 2018 and 2019 forecasts but recommends adopting 2017 adjusted, recorded expenses of \$51.446 million instead of the 2017 forecast. ORA also recommends the creation of a balancing account to record costs of capital expenditures for wells.

13.2.3. Pipelines

This set of projects is associated with upgrading or replacing field piping and related components.

Pipelines	2017	2018	2019
Aliso Valve Replacements	\$880,000	\$880,000	\$880,000
Aliso Pipe Bridge Replacement	\$8,000,000	\$8,000,000	\$0
Blanket Projects	\$11,467,000	\$4,000,000	\$6,800,000
Total	\$20,347,000	\$12,880,000	\$7,680,000

SoCalGas plans to replace various aboveground valves of different sizes and pressures at the Aliso Canyon location. This work is unrelated to the Aliso Canyon leak incident. Each valve replacement is approximately \$20,000. SoCalGas also plans to relocate an existing pipe rack at Aliso that is located in a ravine area. The project cost was derived from a work estimate through a bidding process. Finally, this group of projects includes blanket projects that were estimated using the knowledge and expertise of managers at the storage fields.

Once again, ORA does not object to the 2018 and 2019 forecasts but recommends adopting 2017 adjusted, recorded expenses of \$21.017 million.

13.2.4. Storage Purification Systems

This set of projects is associated with equipment used to remove impurities from natural gas from storage. This includes equipment used for the conditioning of such gas removed from storage.

Purification Systems	2017	2018	2019
Aliso Dehydration Upgrades	\$750,000	\$1,250,000	\$1,250,000
Goleta Dehydration Upgrades	\$0	\$3,050,000	\$0
Blanket Projects	\$4,760,000	\$5,485,000	\$4,360,000
Total	\$5,510,000	\$9,785,000	\$5,610,000

Projects are planned to upgrade the dehydration plans at Aliso Canyon¹²⁸ and Goleta. The projects also include installation new gas and glycol filters for improved gas conditioning and instrumentation upgrades. Costs were forecast using quotes provided by vessel fabricators, equipment manufacturers, contractor estimates, and similar work performed previously. The forecast also includes blanket projects that were estimated using the knowledge and expertise of managers at the storage fields.

ORA does not object to the 2018 and 2019 forecasts but recommends adopting 2017 adjusted, recorded costs of \$2.915 million for 2017.

13.2.5. Storage Auxiliary Equipment

These projects consist of work on various types of field equipment not included in other project groups. Examples of such equipment are instrumentation, measurement, controls, electrical, drainage, infrastructure, safety, security, and communications systems.¹²⁹

¹²⁸ This work is unrelated to the Aliso Canyon leak incident.

¹²⁹ Exhibit 273 at NPN-46.

Auxiliary Equipment	2017	2018	2019
Aliso Overhead Power System Upgrades	\$0	\$1,000,000	\$1,250,000
Aliso Electrical System Upgrades	\$3,450,000	\$2,520,000	\$2,500,000
Aliso Slope Stability	\$1,000,000	\$1,000,000	\$1,000,000
Aliso Sesnon Gathering Plant Relief	\$750,000	\$750,000	\$500,000
Honor Ranch Operations Center Modernization	\$200,000	\$1,000,000	\$1,800,000
Playa Del Rey Erosion & Slope Stability	\$400,000	\$2,500,000	\$1,000,000
Blanket Projects	\$13,406,000	\$10,970,000	\$11,625,000
Total	\$19,206,000	\$19,740,000	\$19,675,000

Aliso Canyon project upgrades are planned to replace the overhead power system with new poles and system infrastructure with new poles and wires to respond to weather conditions and meet electrical standards. These projects were forecast based on historical costs and is unrelated to the Aliso Canyon leak incident. SoCalGas also plans to enhance safety around the Fernando Fee well site to protect against soil erosion and enhance stability. Costs were forecast using a zero-based method. Another Aliso project is a redesign of the Sesnon Gathering Plant by adding a new vessel with drip pot to eliminate pressure points. The forecast for this project also utilized a zero-based methodology.

The Honor Ranch Operations Center Modernization is for the update, modernization and reconfiguration of the control room to allow enhanced operations. Costs were forecast using projects similar in scope.

SoCalGas also plans to improve slope stability and address soil erosion of the Playa Del Rey compressor station which is located along a bluff. Costs were based on recent phases of the project.

SoCalGas also included blanket projects composed of various smaller projects that were estimated using the knowledge and expertise of managers at the storage fields.

ORA does not object to the 2018 and 2019 forecasts but recommends adopting 2017 adjusted, recorded costs of \$17.618 million for 2017.

13.2.6. SIMP

The SIMP capital projects relate to well work mitigation resulting from inspection of SoCalGas' gas storage wells initially inspected in 2016. The second cycle of well inspections is set to begin in 2018 following the two-year inspection cycle proposed by DOGGR. SoCalGas expects additional regulations and orders affecting capital costs will continue to be proposed. The table below shows the forecast for SIMP-related capital projects for 2017, 2018, and 2019. Majority of the costs are associated with inspection and return to operation or workovers, for all fields by the end of TY2019. There are also projects relating to two pilot efforts to monitor integrity and for evaluation of cathodic protection. All projects were forecast using a zero-based method. As with SIMP O&M costs, SoCalGas also requests that SIMP capital costs continue to receive two-way balancing account treatment due to the changing nature of regulations.

SIMP	2017	2018	2019
Plug and Abandonment of Wells	\$3,800,000	\$1,900,000	\$0
Inspection/Return to Operation	\$68,905,000	\$68,120,000	\$46,232,000
Data Management	\$2,580,000	\$1,350,000	\$650,000
Emerging Monitoring Integrity & Safety Technology Pilot	\$0	\$0	\$5,000,000
Cathodic Protection	\$0	\$0	\$1,500,000
Total	\$75,285,000	\$71,370,000	\$53,382,000

Once again, ORA recommends the adoption of 2017 adjusted, recorded costs of \$61.968 million for 2017 but does not object to the forecasts for 2018 and 2019. ORA also recommends that the SIMP balancing account treatment for capital costs be modified into a one-way balancing account for similar reasons stated in its O&M recommendation.

13.2.7. Aliso Canyon Turbine Replacement

The Aliso Canyon Turbine Replacement Project was authorized in D.13-11-023 and was placed into service on May 17, 2018. A more detailed background and description of this project is discussed in section 14 of this decision. The costs being addressed here are capital costs for the project for 2017 and 2018 which are forecast at \$19.602 million and \$1.250 million respectively. ORA does not have any objections or alternative recommendations regarding these costs.

13.2.8. Discussion

ORA makes the same recommendation with respect to all the disputed projects and that is to adopt 2017 adjusted, recorded costs instead of the 2017 forecasts. For its part, SoCalGas states that projects experience delays and several projects planned for 2017 were not yet completed and so those costs were not included in 2017 adjusted, recorded costs. SoCalGas argues that despite the delays, the work still needs to be completed and so the requested funds are necessary. SoCalGas also gave examples of projects that were planned as multi-year projects and that some work may be shifted as priorities change.

From our review of the testimony and arguments by ORA and SoCalGas, we note that ORA provided no explanation why it recommends using 2017 recorded costs and so we assume that the recommendation is based on using more recent data and because actual expenses for 2017 appear to be more reliable than the 2017 forecasts. However, this does not account for the possibility of projects being delayed or re-scheduled as SoCalGas argues. SoCalGas also gave an example of a multi-year project that requires work being performed in 2017, 2018, and 2019 and how some work originally planned for one year can be re-scheduled or re-prioritized to other another year. ORA did not contest the

scope and projected costs of the projects themselves or the forecast methods that were utilized and so we find that ORA's recommendation does not address or respond to the arguments that SoCalGas presented. Thus, between the two parties' arguments, we find that SoCalGas provided more support for its position in the form of testimony and analysis.

We also find that the necessity of the various projects was adequately supported by testimony and ORA did not object to the various forecast methodologies that were utilized. Although we express some concern that delays in 2017 may lead to delays in 2018 and 2019 and cause projects planned for 2019 to not be completed, we expect SoCalGas to properly prioritize projects under this section especially projects that are necessary for safety and compliance with safety-related regulations, as well projects that mitigate key risks. Based on our review, we find that all of SoCalGas' capital project forecasts for UGS totaling \$208.535 million in 2017, \$180.646 million in 2018, and \$172.606 million in 2019, should be authorized.

Following our discussion of the two-way balancing treatment for O&M costs, we likewise find it reasonable to authorize the SIMPBA to continue to record capital costs relating to SIMP and to continue the balancing account treatment established in D.16-06-054 for recovery of booked costs. For capital projects, the SIMPBA shall also continue to be maintained as a two-way balancing account subject to the same recovery procedure established in D.16-06-054 for any undercollections from the authorized amount. Any unused funds are to be returned to ratepayers.

Finally, we find that ORA's request for a balancing account to record capital expenses for wells is not necessary. ORA's recommendation is based on its concern that SoCalGas will not be able to complete seven well replacements

planned for 2019 because it only plans to replace a total of four wells in 2017 and 2018. However, as SoCalGas explains, fewer projects are planned for 2019 for the other project groups under Storage Wells in recognition of the greater number of well replacements planned for 2019. As shown in section 13.2.2., the requested amounts for most of the other project groups under Storage Wells are less for 2019. SoCalGas also cited a specific example regarding well plug and abandonments wherein only five are planned for 2019 compared to 40 for 2017 and 17 for 2018.

14. Aliso Canyon Turbine Replacement

In D.13-11-023,¹³⁰ this Commission granted SoCalGas' authority to "construct and operate the Aliso Canyon Turbine Replacement Project to replace three obsolete gas turbine driven centrifugal compressors and associated equipment with a new electric compressor station and construction of other improvements at the Aliso Canyon storage field."¹³¹

The decision authorized a total cost \$200.9 million for the project but also directed that if actual costs exceeded \$200.9 million, "a reasonableness review of all project costs must be conducted in SoCalGas' general rate case following completion of the project."¹³² The decision added that efforts to maximize the O&M cost savings and capital benefits be reviewed as well. Costs exceeding the authorized amount of \$200.9 million were to be tracked in a memorandum account.

¹³⁰ Decision in A.09-09-020 which became effective November 11, 2014.

¹³¹ D.13-11-023 OP 1 at 69.

¹³² D.13-11-023 OP 12 at 73.

The project was completed and placed into service on May 17, 2018; and in this application, SoCalGas seeks to establish the reasonableness of the \$275.5 million of actual project costs to complete the project and to recover \$74.6 million in costs representing the amount that actual costs exceed the authorized cost in D.13-11-023 of \$200.9 million. SoCalGas states that total project costs actually exceed \$275.5 million by approximately \$11.9 million.¹³³ However, SoCalGas did not update its testimony to include this amount and is not seeking recovery of this amount of \$11.9 million in this GRC.

14.1. Project Cost Elements

The project cost of \$200.9 million in A.09-09-020 was developed using major project cost elements. In this application, SoCalGas uses these same cost elements but with adjustments to each one. The table below shows a list of these major project cost elements as well as a breakdown of estimated costs and the corresponding estimated costs at completion and the variance between the two totaling \$74.6 million.

Scope	A.09-09-020 (2009)	Completion (2018)	Variance
Central Compressor Station	\$166,000,000	\$146,600,000	(19,400,000)
Environmental	\$1,000,000	\$13,000,000	\$12,000,000
Substation & Electrical Infrastructure	\$10,200,000	\$23,900,000	\$13,700,000
Buildings	\$900,000	\$13,500,000	\$12,600,000
Other	\$200,000	\$8,400,000	\$8,200,000
Company Labor	\$0	\$7,200,000	\$7,200,000
Indirects	\$22,600,000	\$62,900,000	\$40,300,000
Total	\$200,900,000	\$275,500,000	\$74,600,000

¹³³ Exhibit 279 Appendix A at DLB-A-1.

Central Compressor Station

The Central Compressor Station accounts for approximately 70 percent of direct costs for the entire project and is the largest component of the project. The station houses three new electric-driven, variable-speed compressors, along with scrubbers, piping, coolers, and electrical equipment.¹³⁴ Construction activities include clearing and grading, construction of building and equipment foundations, construction of compressor housing stations, construction and installation of associated control equipment, air cooled heat exchangers, other equipment, and piping. Construction includes a 500-foot aboveground pipeline for moving compressed gas into the storage field. Costs also include pre-engineering, engineering services, and procurement.

Environmental

Environmental costs are primarily costs to retain consultants to comply with California Environmental Quality Act requirements including costs for the preparation of the Environmental Impact Report (EIR).

Substation and Electrical Infrastructure

According to SoCalGas, the replacement of gas turbines with electrical compressors required construction and operation of a new substation to provide electric service at the Aliso Canyon Storage Field and SCE was contracted to provide the substation.

Buildings

The buildings component represents costs for relocation of a guard house and the replacement of office buildings.

¹³⁴ Exhibit 277 at DLB-13.

Others

This cost category is for construction activities associated with fill sites, temporary office trailers, project controls support and increased site security.

Company Labor

These are for labor costs including assessment of environmental impacts in aid of the development of the EIR, planning and development, and actual project activities.

Indirects

Indirect costs include overhead costs associated with direct costs such as payroll taxes and pension and benefits. Also included are Allowance for Funds Used During Construction (AFUDC) and property taxes.

14.2. Positions of Intervenors

ORA is the only party that provided comments for this section and while ORA does not take issue with SoCalGas' presentation of its testimony at this time, ORA recommends that a full audit of SoCalGas' expenditures be performed by the Commission or an assigned entity to determine the reasonableness of all charges or to conduct a reasonableness review in the next GRC.

14.3. Discussion

D.13-11-023 provided a mechanism for reviewing costs in excess of the \$200.9 million that was already authorized in that decision. In Ordering Paragraph (OP) 12, the decision provides that after completion of the project, a reasonableness review of project costs as well as efforts to maximize O&M cost savings and capital benefits should be conducted in the following GRC. The project was fully completed and placed into service on May 17, 2018 and this GRC is the GRC following completion of the project. Thus, we find that the

reasonableness review of the project should be conducted in this GRC and not in the next GRC.

With respect to ORA's recommendation that the Commission conduct an audit of all project costs, we note that ORA did not express any concerns with SoCalGas' presentation of testimony in this GRC and did not present any specific reasons or concerns to be addressed in its recommendation that an audit be conducted such as insufficiency or incorrectness of the evidence presented. Thus, we find that a reasonableness review in this GRC is sufficient to resolve the requests being made.

We reviewed the testimony presented in this GRC as well as the findings made in D.13-11-023 and focus our review on the portion of the costs that exceed project cost of \$200.9 million authorized in D.13-11-023. The review and analysis conducted in D.13-11-023 sufficiently established the necessity of the project as well as the reasonableness of the project cost authorized in that decision. We find that it is not necessary to go over these issues again and that it is appropriate to adopt the findings made in D.13-11-023. We also note that D.13-11-023 recognized that actual costs authorized for the project may exceed the authorized amount and provided a mechanism for which to seek recovery thereof and which SoCalGas complied with.

With respect to the \$74.6 million variance, we reviewed the seven major project cost elements and separately examined the reasonableness of the variances presented in each cost element. These project elements are the same ones that were presented and reviewed in D.13-11-023. We also examined SoCalGas' efforts to maximize O&M cost savings capital benefits as directed by D.13-11-023.

Generally, in explaining the reason for the overall variance of \$74.6 million, SoCalGas cites to the significantly expanded scope of the project following the increased environmental impacts identified in the EIR and the increased mitigations that were required as a result thereof. SoCalGas also cites to the lengthy delay in completing the project, and that the costs that were previously developed and identified in A.09-09-020 reflect base year 2009 nominal dollars. SoCalGas claims that price escalation alone would compare to approximately \$232 million today.¹³⁵

We reviewed the timeline of the project and do not disagree that the project was not approved until November 22, 2013, or more than four years from the time the application was filed. SoCalGas' original timeframe projected that the project would be completed in approximately one year, but we find that the expanded scope of the project, which required additional planning and redesign justifies the additional delay. Thus, we find that SoCalGas is not responsible for delays to the completion of the project.

For the Central Compressor Station, cost-saving efforts included contracting of services with a firm to assist in competitive solicitation of bids from 19 qualified contractors, hiring of an engineering firm to provide expert design and construction oversight, savings from design optimization, application of drilling methods in certain areas as opposed to excavation, and use of a soil nail wall instead of a concrete wall. Collectively, projected costs were reduced by \$19.4 million from the original estimate in 2009.

¹³⁵ Exhibit 277 at DLB-32.

Environmental costs increased significantly from the 2009 estimate because the EIR issued by the Commission identified additional and more significant potential environmental impacts that needed to be addressed, which required more time and resources than contemplated in the 2009 estimate. There were also added costs for activities which we find to be necessary such as surveying and monitoring used to prepare the EIR, SoCalGas' compliance costs which included construction and vegetation clearing, and mitigation costs which also included construction and habitat, vegetation, and tree mitigation activities.

The design for the SCE substation were modified to meet design requirements for the Central Compressor Station and site preparation costs were higher than anticipated because of additional needs such as better access, requirements because of the new design, a new ordinance requiring a biofiltration system, and additional environmental monitoring required by the EIR. In an effort to lower costs, SoCalGas conducted a competitive solicitation for construction of a plant power line.

For Buildings, most of the increased costs was a result of SoCalGas' decision to replace existing office trailers with a permanent steel building in order to increase size and to afford extra protection against wind, fire, and other elements, and thereby enhance safety. Other enhancements from the original plan include enhanced access to comply with anticipated safety-related regulations.

Increased costs in the Others cost category was mostly due to the construction of four new fill sites in part because of requirements from the EIR. An already available fill site that was contemplated in the 2009 plan was not available for the project when construction began because it was utilized for another project.

For Company Labor, the original plan was to use only a small team to provide management and oversight over third-party contractors that would execute project activities. As the project progressed, SoCalGas deemed it more prudent to use company employees to perform activities that would have been performed by third-party contractors. The overall increase in the scope of the project contributed to higher labor costs.

Regarding the increase in indirect costs, the majority of the increased costs are due to the change in scope of the project. Direct capital costs increased by \$34.3 million, resulting in increased overhead costs as well. AFUDC and property taxes increased significantly because of the extended length of time it took to complete the project. Since the costs here are derivative in nature, very little cost-saving methods were available.

Cost savings and capital benefits concerning the replacement of obsolete gas compressors are detailed in Table DLB-10 and DLB-11 of Exhibit 277. Savings include reductions in third-party and labor costs, reduced storage, reduced air emission fees, etc. while capital benefits include reduced demand for Regional Clean Air Incentives Market Trading Credits and reduced GHG emissions.

Based on our review and analysis of the above, we find that the testimony presented supports the reasonableness of the \$275.5 million in capital expenditures to complete the Aliso Canyon Turbine Replacement Project and that SoCalGas should be authorized to recover in rates the \$74.6 million in costs which exceed the previously authorized amount in D.13-11-023. We also find that the request to continue the Aliso Canyon Memorandum Account (ACMA) to record additional capital-related costs in excess of \$275.5 million is reasonable.

Any recovery sought for such amounts should be subject to a reasonableness review in SoCalGas' next GRC.

15. Gas Control and System Operations and Planning

This section addresses SoCalGas' TY2019 forecast for Gas Control and System Operations and Planning. SoCalGas' forecast for TY2019 is \$8.958 million in O&M costs. There are no associated capital expenditures. The forecast represents an increase of \$2.931 million over 2016 adjusted, recorded expenses. A large part of the increase is associated with incremental costs for Emergency Services. All costs were forecast using five-year average methodology.

Costs associated with Emergency Services and Supervisory Control and Data Acquisition (SCADA) activities are presented by SoCalGas as RAMP-related costs although these costs were not included in the RAMP Report. Rather, these costs are presented in the GRC as post-RAMP additions following the comment process in the RAMP proceeding and final review of RAMP risks, costs, and requests to be included in the GRC. The RAMP risks being mitigated are employee, contractor, customer, and public safety and catastrophic damage involving high pressure pipeline failure. The total RAMP costs requested for this section is \$5.708 million and these will be reviewed in the cost categories where they are included.

Consistent with other applicable sections of the decision, costs pertaining to the Aliso Canyon gas leak incident are excluded from the forecast and from historical averages.

This section shall also address the IT Business Unit capital projects requested under this section.

15.1. Non-Shared Costs

Non-shared costs for Gas Control & System Planning are forecast at \$2.972 million which is \$2.186 million higher than 2016 adjusted, recorded expenses for 2016.

15.1.1. Storage Products Manager

The Storage Products Manager group operates the California Energy Hub (CEH) to provide unbundled natural gas storage and parking services such as natural gas storage, traditional hub services such as natural gas parking and loaning,¹³⁶ and natural gas sales from projects authorized by the Commission. The TY2019 forecast for this group is \$0.156 million which is around \$10,000 higher than base year levels.

15.1.2. Emergency Services

The forecast for Emergency Services is \$2.816 million which is \$2.176 million higher than 2016 adjusted, recorded costs. This department supports SoCalGas' goal of maintaining comprehensive and coordinated emergency response and recovery programs to comply with federal and state requirements. SoCalGas intends to add 13 positions in addition to the six employees that currently support the functions.

15.1.3. Positions of Intervenors

ORA provided comments to SoCalGas' non-shared forecast. ORA recommends \$1.145 million which is SoCalGas' recorded costs for 2017. ORA states that SoCalGas' request is excessive and that spending from 2012 to 2016 ranged from \$0.640 to \$0.905 million.

¹³⁶ Natural gas parking is the temporary storage of natural gas on the SoCalGas system, and natural gas loaning is the temporary lending of natural gas from the SoCalGas system.

15.1.4. Discussion

ORA's analysis is that spending has not exceeded \$1 million from 2012 to 2016 and that the establishment of emergency response procedures pursuant to GO 112-F was required to be complied with no later than January 1, 2017. Thus, ORA argues that recorded costs of \$1.145 million in 2017 were already sufficient to comply with GO 112-F.

Based on our review however, the 2017 costs do not include compliance with other requirements such as the Gas Emergency Management Program required by GO 112 and the training and certification requirements required by the California Division of Occupational Safety and Health department regarding the Incident Command System. The additional FTEs being requested will enable SoCalGas to monitor and administer the required trainings and to implement a recommendation by SED to enhance the frequency of emergency preparedness and response exercises and coordination with first responders and public officials regarding said trainings.

In addition, pursuant to the RAMP process, SoCalGas proposes to conduct certain activities beyond the minimum requirements set forth by GO 112-F in order to enhance its response and recovery programs for employees and its natural gas system operations as well as the public awareness program with first responders. SoCalGas adds that additional resources are necessary to maintain and enhance programs under GO 112-F such as improving an Incident Command System that complies with the general order and implementing emergency procedures and training.

Given that Emergency Services is on call 24 hours a day and in light of the recent wildfires and atypical weather conditions, we find that there is an

increased need for emergency response preparedness and coordination with other first responders.

Based on the above, we find SoCalGas' request for additional FTEs for Emergency Services to be reasonable and necessary in order to enhance SoCalGas Emergency Services capabilities. We also find the forecast for the Storage Products Manager group to be reasonable and therefore find that the total forecast for non-shared costs of \$2.972 for TY2019 should be approved. The above forecast will provide the necessary funding for a resulting total of 18.5 FTEs for Emergency Services. We also agree with SoCalGas that the appropriateness of the funding level being authorized can be reviewed when it files its RAMP spending and accountability reports.

15.2. Shared Costs

SoCalGas' TY2019 forecast for shared costs is \$5.986 million which is \$0.745 million higher than base year adjusted, recorded costs. Shared costs include costs for four departments: Energy Markets & Capacity Products, Gas Scheduling, Gas Transmission Planning, and Gas Control and SCADA Operations.

15.2.1. Energy Markets & Capacity Products

The forecast for Energy Markets & Capacity Products is \$1.550 million which is around base year levels. This group is comprised of the director, Capacity Products Manager, and Capacity Products Support. The group provides services for gas marketers that serve SoCalGas and SDG&E customers, large nonresidential customers who choose to act as their own gas supplier, and core aggregators. The group also manages business relationships, provides

analytical and regulatory compliance support, and represents SoCalGas in the development and modification of gas industry standards for gas scheduling.¹³⁷ The group also monitors market pricing information and recommends changes to capacity and storage. The group also develops and maintains SoCalGas' and SDG&E's electronic bulletin board called Envoy.¹³⁸

15.2.2. Gas Scheduling

Gas Scheduling manages the day-to-day system and operation for nominations, allocations, and scheduled gas transportation as well as the Operational Flow Order rules. Gas Scheduling also tracks storage accounts, tracks and clears shipper imbalances, and administers the imbalance trading process. Gas Scheduling also makes regular postings on Envoy. The TY2019 forecast for this group is \$0.724 million which is \$0.124 million higher than 2016 costs.

15.2.3. Gas Transmission Planning

Gas Transmission Planning is responsible for long-term planning and design of Applicants' gas transmission systems and continually assesses the system's ability to meet Commission design standards, service obligations, and to satisfy new demand to the system. The forecast for Gas Transmission Planning is \$0.691 million which is \$84,000 higher than base year levels.

15.2.4. Positions of Intervenors

Comments to the shared services forecasts were provided by ORA, SCGC, and EDF.

ORA does not take issue with any of the shared services forecasts.

¹³⁷ Exhibit 17 at DKZ-3.

¹³⁸ This is the name of the Applicants' electronic bulletin board and is not an acronym.

SCGC recommends that SoCalGas be authorized to spend an additional \$1 million in 2019 to incorporate the trading of Daily Scheduled Quantities into Envoy's electronic bulletin board system.

EDF recommends that SoCalGas automate its imbalance trading within the Envoy system to enable "day after" flow imbalance trading. EDF also initially recommended that SoCalGas allocate funding to create a plan to address operational and market risks associated with gas and electric coordination. We find that these issues are addressed in the RAMP Report and proposed mitigations such as real-time monitoring of the transmission system and remote monitoring of gas and electric systems are already proposed in the GRC. EDF did not raise this issue again in its opening brief.

15.2.5. Discussion

We reviewed the TY2019 shared services forecast for Gas Control & Systems Operations and find the proposed costs to be reasonable and necessary to carry out the various functions performed by the Gas Control Systems Operations division. SoCalGas provided sufficient testimony to support its requested costs including an explanation of the cost drivers for the \$0.745 million increase from base year recorded costs. We also find the forecast methodology of using a five-year historical average to be appropriate. Parties did not object to the proposed costs. Thus, we find that the proposed forecast of \$5.986 million for TY2019 for shared services costs is reasonable and should be approved.

With regards to proposals by SCGC and EDF concerning automation of SoCalGas' daily imbalance trading, the assigned ALJ issued an oral ruling during the evidentiary hearing on July 10, 2018 that all core balancing issues are outside

the scope of these GRC proceedings as determined by the assigned Commissioner.¹³⁹ The ruling adds that such issues are better raised in the core balancing proceeding.¹⁴⁰ In a subsequent ruling issued on September 17, 2018, the assigned ALJ further clarified that funding requests for proposals by EDF and SCGC relating to core balancing to actual demand, as well as the proposal for automation, should likewise be raised and addressed in the core balancing proceeding.

EDF states that the core balancing proceeding only applies to core customers and not to non-core customers. We agree with EDF but find that there is only a single process for core balancing to actual demand for both core and non-core customers. A decision modifying the process (such as automation) of the daily imbalance trading for core customers would also apply to non-core customers. It would be duplicative for the Commission to decide a single process in two separate proceedings and may lead to inconsistencies. Thus, we find it reasonable and prudent to defer judgment on these issues as it applies to non-core customers to the Commission's resolution of these issues in A.17-10-002.

15.3. Operational Flow Cost Memorandum Account

SoCalGas requests that the Commission allow recovery of expenditures recorded in the Operational Flow Cost Memorandum Account (OFCMA) in the amount of \$1.696 million.

¹³⁹ Transcript Volume 11 at 579-580.

¹⁴⁰ A.17-10-002 filed by SDG&E and SoCalGas on October 2, 2017.

The OFCMA was authorized in D.15-06-004¹⁴¹ to record expenditures for SoCalGas' Operational Flow Order (OFO) and Emergency Flow Order (EFO) activities. The low OFO and EFO establish procedures that trigger when it is forecast that the storage withdrawal allocated to the balancing function will be exhausted or when there is an actual supply or capacity shortage that threatens deliveries to end-use customers. Costs tracked in the OFCMA are to be recovered in the GRC. And as stated above, SoCalGas seeks recovery of \$1.696 million in capital expenditures that have been tracked in the memorandum account.

SoCalGas states that the costs incurred were for major system enhancements required in Envoy and the Specialized Core Billing System in order to execute the OFO and EFO implementation. The enhancements included the creation of new screens to view and process low OFO calculations, modifications to the Gas Scheduling process to replace the "winter balancing rules" with the new procedures, creation of new alerts, and updates to accommodate changes to the billing system.¹⁴²

We reviewed SoCalGas' request and find that SoCalGas provided sufficient testimony to support its request. The testimony provides sufficient detail regarding the costs incurred as well as the necessity thereof. SoCalGas also complied with the requirements set forth in D.15-06-004 and submitted the necessary periodic reports that are detailed in Table DKZ-11 of Exhibit 17.¹⁴³

¹⁴¹ D.15-06-004 OP 13 at 43 to 44.

¹⁴² Exhibit 17 at DKZ-35.

¹⁴³ Exhibit 17 Table DKZ-11 at DKZ-34 to 35.

Parties did not object to the reasonableness of the proposed costs. Therefore, we find that the \$1.696 million balance in the OFCMA are reasonable and authorize recovery thereof in rates. However, we find ORA's proposal to normalize cost recovery over the 2018 and 2019 period is not necessary because of the relatively minimal impact on rates.

15.4. IT Business Unit Capital Projects

SoCalGas is also requesting \$3.401 million in 2017, \$3.806 million in 2018, and \$4.771 million in 2019 for six IT-related projects. The projects are described in Exhibit 17.¹⁴⁴ Additional details are provided in the capital workpapers of witness Olmsted.

We reviewed all six projects and find the requested amounts reasonable and should be approved. Four of the projects provide upgrades to SoCalGas' Envoy system replacing outdated software and providing system enhancements that allow necessary functionalities and increased security. The other two projects are for communication trailers that support first responders and replacement of an outdated system that supports important gas operations functions. Parties do not oppose these proposed capital projects.

16. Pipeline Integrity for Transmission and Distribution

This section addresses costs associated with the Pipeline Integrity for Transmission and Distribution organization which is responsible for implementing and managing requirements set forth in 49 Code of Federal Regulations (CFR) section 192, Subpart O and Subpart P.

¹⁴⁴ Exhibit 17 at 22 to 25.

Compliance with Subpart O is accomplished through the Transmission Integrity Management Program (TIMP) which requires Applicants to “identify threats to transmission pipelines in HCA, determine the risks posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators.”¹⁴⁵

Meanwhile, compliance with Subpart P is accomplished through the Distribution Integrity Management Program (DIMP) which requires Applicants to “collect information about their distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to the distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce risks from failure of the gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators.”¹⁴⁶

TIMP and DIMP are relatively new federal code requirements that go beyond routine maintenance activities by monitoring and remediating risk on the gas pipeline system and maintaining the integrity of the gas system. TIMP manages risk reduction through assessments and remediation of transmission pipelines in populated areas on a recurring schedule while DIMP implements

¹⁴⁵ Exhibit 111 at MTM-3.

¹⁴⁶ *Id.* at MTM-3 to 4.

target activities, programs, and projects that provide an extra layer of monitoring, assessment, and proactive remediation.¹⁴⁷

16.1. SoCalGas

SoCalGas' total forecast for TIMP and DIMP is \$86.00 million for TY2019 O&M costs and capital costs of \$125.184 million each for 2017 and 2018, and \$215.00 million in 2019.

Certain costs are associated with mitigation of key RAMP risks identified in the RAMP Report. These are Catastrophic Damage Involving High-Pressure and Medium-Pressure Pipeline Failure and Records Management. Total RAMP-related costs associated with TIMP and DIMP is \$86.00 million for TY2019 O&M costs and capital costs of \$125.184 million each for 2017 and 2018, and \$215.00 million for 2019.¹⁴⁸ Incremental RAMP costs for TIMP and DIMP are approximately \$8.317 million for TY2019 O&M costs and capital costs of \$9.600 million for 2017, \$6.500 million for 2018, and \$102.846 million for 2019.¹⁴⁹ Most of the incremental RAMP costs are associated with the DIMP Distribution Risk Evaluation and Monitoring System (DREAMS) and the Gas Infrastructure Protection Project that is also part of DIMP.

Pursuant to D.16-06-054, costs associated with the Aliso Canyon gas leak incident are excluded from the forecast and from historical data.

16.1.1. O&M

The TY2019 forecast of \$86.00 million is \$10.342 million higher than 2016 adjusted, recorded costs. Both non-shared and shared costs are simply

¹⁴⁷ Exhibit 111 at MTM-3 to 4.

¹⁴⁸ Exhibit 111 at MTM-5, Table MTM-2.

¹⁴⁹ Exhibit 111 at MTM-8 to MTM-10, Tables MTM-5 & 6.

comprised of costs associated with TIMP and DIMP. The table below shows the breakdown of both non-shared and shared O&M costs for TIMP and DIMP. All forecasts utilized a zero-based methodology because historic averages do not reflect anticipated changes in scope from year to year and because both programs are still relatively new.

O&M	Non-shared	Shared	Total TIMP or DIMP
TIMP	\$44,351,000	\$1,649,000	\$46,000,000
DIMP	\$38,359,000	\$1,641,000	\$40,000,000
Total Non-shared and Shared	\$82,710,000	\$3,290,000	\$86,000,000

16.1.1.1. TIMP

The activities prescribed by Subpart O are categorized into seven topic areas and are briefly described below:

Threat Identification and Risk Assessment

All pipelines operated in HCAs are evaluated for nine threat categories which are “external corrosion, internal corrosion, stress corrosion cracking, manufacturing, construction, equipment, third party, incorrect operations, and weather related and outside force.”¹⁵⁰ Risk assessment is conducted by relative assessment of relevant threats and industry data.

Assessment Plan

Once HCA pipelines are prioritized, an assessment plan is created to manage the scheduling and due dates for all assessments.

¹⁵⁰ Exhibit 111 at MTM-14.

Assessment

The primary assessment methods utilized are in-line inspection,¹⁵¹ pressure testing, external corrosion direct assessment, and internal corrosion direct assessment.

Remediation

Remediation is conducted through repair or reconditioning of a pipeline coating and can include replacement.

Additional Preventative and Mitigative Measures

Performed once data is analyzed and there is need is identified for such additional measures.

Geographic Information System (GIS)

A computer system that presents all types of geographic data and is used to manage medium and high-pressure pipelines.

Auditing and Reporting

Relevant integrity data is reported to the PHMSA annually. Copies of the report are provided to the Commission. The report includes the total system miles, the number of miles inspected, number of HCA miles, and number of HCA miles inspected.

Costs to implement TIMP are balanced and recorded in the TIMP Balancing Account (TIMPBA) and excess costs due to unanticipated activities may be requested through an advice letter.

16.1.1.2. DIMP

DIMP activities prescribed by Subpart P are as follows:

¹⁵¹ In-line inspection utilizes specialized inspection tools that travel inside the pipeline.

System Knowledge

Data collection includes “understanding of system attributes which include design, materials, construction methods, pipeline condition, past and present operations, maintenance, local environment factors, and failure data.”¹⁵²

Threat Identification and Risk Analysis

The major incident categories are excavation damage, other outside force damage, corrosion, material or welds, equipment failure, natural force damage, and incorrect operations.

Programs/Projects and Activities to Assess Risk (PAAR)

PAAR programs are intended to address risk and implemented through different avenues depending on the threat being addressed.

GIS

Same as described in TIMP in 6.1.1.1. above.

Reporting

Same as described in TIMP in 6.1.1.1. except for the content of the report which is excavation damages, leaks repaired, hazardous leaks repaired, and mechanical fitting failures.

As with TIMP, costs to implement DIMP are balanced and recorded in the DIMP Balancing Account (DIMPBA) and excess costs due to unanticipated activities may be requested through an advice letter.

16.1.2. Capital

TIMP and DIMP capital costs are set forth in the table below. According to SoCalGas, recent incidents in the gas industry have upward pressures on TIMP

¹⁵² Exhibit 111 at MTM-20.

to expand inspections and on DIMP to analyze risks and implement programs and activities to address risk at an accelerated pace. All forecast methods were developed using a zero-based methodology.

Capital	2017	2018	2019
TIMP	\$50,801,000	\$50,801,000	\$55,000,000
DIMP	\$74,383,000	\$74,383,000	\$160,000,000
Total	\$125,184,000	\$125,184,000	\$215,000,000

16.1.3. Positions of Intervenors

Comments were provided by ORA, TURN, CUE, CFC, and OSA.

ORA recommends using 2017 adjusted, recorded costs of \$193.425 million for 2017 TIMP and DIMP capital costs but has no objections to the rest of SoCalGas’ O&M and capital forecasts.

TURN recommends removal of costs for clothing and gear other than uniforms in the amount of \$4,359.

CUE recommends that the capital budget for 2019 be increased to \$532.72 million or \$385.965 million more than SoCalGas’ request based on accelerated replacements for the Vintage Integrity Plastic Plan (VIPP) program to replace pre-1986 Aldyl-A gas pipes and the Bare Steel Replacement Plan (BSRP) program to replace bare steel pipes without cathodic protection. Aldyl-A is a type of plastic which was used in gas pipes installed by SoCalGas starting in the late 1960s. These pipes, particularly those installed before 1973, are particularly prone to cracking and leaking. CUE also recommends an increase to the Distribution Riser Inspection Program (DRIP).

CFC recommends a reduction of \$1.759 million to the 2019 DIMP capital forecast because of improved leak performance and because safety must be balanced with affordability. CFC also states that future increases be subject to

the advice, assessment, and recommendation of the three project advisors that SoCalGas intends to add.

CUE also raised concerns in connection with the DRIP that contractors are not familiar with SoCalGas' facilities which impair their ability to detect abnormal conditions but we agree with SoCalGas that only qualified contractors perform the DRIP inspections and that many contractors have worked on SoCalGas' facilities for a number of years. The DRIP inspections are also conducted on top of more routine maintenance inspections performed.

OSA states that TIMP should be expanded to address non-HCA areas and that data obtained from tests should be validated.

In its rebuttal testimony, SoCalGas states that all parties recommend adopting its 2017 adjusted, recorded capital costs.

16.1.4. Discussion

The activities associated with TIMP and DIMP are performed pursuant to compliance with regulatory requirements mandated by 49 CFR section 192, Subpart O and Subpart P. TIMP manages risk reduction through assessments and remediation of transmission pipelines while DIMP implements target activities, programs, and projects that provide an extra layer of monitoring, assessment, and proactive remediation. We find the activities associated with TIMP and DIMP as well as the RAMP-related activities to be necessary in promoting the safe provision of natural gas services, mitigating key risks, and compliance with the regulatory requirements mandated by Subpart O and Subpart P.

O&M Costs

Parties generally do not object to SoCalGas' O&M forecast except for a recommended disallowance by TURN of \$4,359 for clothing and gear and CUE's

recommended increase of \$3.743 million. The increase recommended by CUE are resulting O&M increases associated with CUE's recommended acceleration and increases to SoCalGas' capital programs. We shall address this issue in our discussion of the capital portion of this section. Regarding TURN's recommendation, we find that a de minimis amount of less than five thousand dollars spent on clothing and gear used in conjunction with customer events to create awareness of customer programs and services is reasonable and not for promotional purposes. Additionally, TURN did not raise its initial objection in briefs. Therefore, we find that SoCalGas' TY2019 forecast for O&M costs of \$86.00 million is reasonable and should be approved.

2017 Capital Costs

With respect to the use of 2017 recorded data for 2017 capital costs, this decision has generally stayed away from applying select updating of 2016 data used in the application to 2017 data. As mentioned in other sections of this decision, updating only select data may lead to inconsistent results as not all data is being updated. For example, updating data in this section where recorded costs in 2017 are tens of millions greater than the 2017 forecast would be inconsistent if, for example, the Cybersecurity section is not updated as well where capital spending in 2017 is tens of millions less than the 2017 forecast. And we find that it is not practical to update all data. We do, however, recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and we shall exercise our discretion in doing so in appropriate cases.

For TIMP and DIMP capital costs however, we find that the testimony and other evidence submitted by SoCalGas adequately supports the 2017 forecast but

there is little evidence submitted in this application to support the 2017 recorded spending,¹⁵³ which is more than \$68 million higher than the 2017 forecast.

In any case, TIMP and DIMP costs are subject to a two-way balancing account treatment through the TIMPBA and DIMPBA respectively. As adopted in the past two SoCalGas GRC decisions¹⁵⁴, recovery of any TIMP or DIMP undercollections will be limited to undercollection amounts up to 35 percent of the total revenue requirement for that program and will require a Tier 3 advice letter. Amounts above 35 percent will be subject to a separate application procedure. Under this recovery process, SoCalGas will be provided with the appropriate safety spending and should be able to appropriately explain and provide information regarding the spending. Therefore, we find it reasonable to authorize the forecast amount of \$125.184 million for 2017 capital costs.

2018 Capital Costs

Parties do not object to the capital forecast for 2018 and we find this to be reasonable and supported by the evidence.

2019 Capital Costs

A large portion of CUE's recommended increases are associated with CUE's recommended acceleration to the replacement rates for the VIPP and BSRP programs. CUE recommends that the Aldyl-A pipe replacement in the VIPP program be increased from 78 miles to 223 miles in 2019 and for the rate of replacement of bare steel pipes in the BSRP program to be increased from 29 miles to 103.5 miles in 2019. These two recommendations alone amount to an

¹⁵³ SoCalGas did provide in Exhibit 114 at MTM-11 that the replacement rate of vintage steel and plastic was 8 miles more than the forecast of 55 miles.

¹⁵⁴ D.13-05-010 and D.16-06-054.

increase of \$191.4 million and \$60.04 million respectively over SoCalGas' proposed capital budget for 2019 of \$215.0 million. CUE states that SoCalGas' planned replacement rate is well below the pace required to replace all Aldyl-A and bare steel pipes within the 25 to 30 years it had originally projected.

While we agree with CUE that the VIPP, BSRP, and DRIP are important programs that address safety risks from pipes that are composed of materials that present a greater amount of risk, the RAMP Report shows that there are other key pressing safety risks that must be addressed. In addition, the various safety mitigation activities, plans and programs must also be prioritized and balanced with keeping rates affordable. We must also consider SoCalGas' labor and non-labor resources and ability to comply with the replacement rate that CUE is recommending even if we were to increase the authorized amount being requested. In reviewing the evidence presented and the arguments raised by parties, we find that SoCalGas' proposed costs and replacement rate in this GRC for the VIPP, BSRP, and DRIP programs are reasonable and within SoCalGas' means to complete. In its next GRC however, SoCalGas should also include an outlook of its long-term assessment and replacement plan for Aldyl-A pipes and bare steel pipes without cathodic protection, in addition to what it plans for the next GRC cycle as it appears that its current replacement rate is not on pace with its original assessment.

On the issue of SoCalGas' improved leak performance, the VIPP and BSRP programs focus on replacement of plastic and vintage steel pipes as opposed to basing the replacement rate on leaks. Thus, we find that improved leak performance has little effect on the above programs which target wholesale replacement of pipes. Regarding the three project advisors that SoCalGas plans to add, SoCalGas states that the three advisors are being added to Gas

Distribution's focus on leak reduction efforts and have little to do with determining the rate of replacement of plastic and vintage steel. Therefore, we find that CFC's proposals should be denied.

Based on the above, we find that SoCalGas' forecast of \$215.00 million for capital projects in 2019, should be approved.

OSA Issues

With respect to OSA's comments, SoCalGas responds that TIMP inspections have been proactively expanded over the years to include non-HCA areas which are beyond the current requirements set forth by Subpart O.¹⁵⁵ We agree with this approach although SoCalGas should continue to properly prioritize what pipelines are to be inspected as the amount of pipelines that can be tested and inspected is limited as compared to the total length of pipelines in its distribution and transmission system. With regards to validation of test results, it is not clear and OSA did not elaborate what sort of validation it had in mind. Thus, we reiterate our suggestion in the Gas Integrity section of the decision that OSA consider becoming a party in SoCalGas' next RAMP proceeding and propose and explain this and other appropriate recommendations in the next RAMP proceeding.

16.2. SDG&E

SDG&E's gas transmission and distribution system are subject to the same requirements prescribed by 49 CFR section 192, Subpart O and Subpart P and the underlying O&M and capital costs are the same as those for SoCalGas except for the size of its system which is composed of 14,088 miles of interconnected gas

¹⁵⁵ Exhibit 114 at MTM-9.

mains and services compared to 99,872 miles for SoCalGas. The tables below show the O&M and capital forecasts. All forecasts were developed using a zero-based methodology. Total RAMP-related costs associated with TIMP is \$9.0 million and \$51.0 million for DIMP.

O&M	Non-shared	Shared	Total TIMP or DIMP
TIMP	\$5,000,000	\$0	\$5,000,000
DIMP	\$6,000,000	\$0	\$6,000,000
Total Non-shared and Shared	\$11,000,000	\$0	\$11,000,000

O&M costs for TY2019 are \$3.256 million higher than base year adjusted, recorded costs. The description of TIMP and DIMP activities to be conducted are the same as those described in sections 16.1.1.1. and 16.1.1.2. in the SoCalGas section.

Capital	2017	2018	2019
TIMP	\$3,997,000	\$3,997,000	\$4,000,000
DIMP	\$20,219,000	\$20,219,000	\$45,000,000
Total	\$24,216,000	\$24,216,000	\$49,000,000

16.2.1. Positions of Intervenors

ORA and CUE provided comments to the SDG&E portion. Both parties make similar recommendations as they did in the SoCalGas portion.

ORA recommends using the 2017 adjusted, recorded costs of \$36.808 million for 2017 capital and does not object to the O&M and 2018 and 2019 capital forecasts.

CUE recommends increasing the 2019 capital forecast to \$251.558 million or \$154.156 million higher than SDG&E's based on its recommendation to accelerate the VIPP program to replace pre-1986 Aldyl-A gas pipes and to accelerate the DREAMS program pipe replacement from 27 to 126 miles per year.

CUE also recommends an increase of \$762,000 to SDG&E's O&M forecast because of associated costs with its proposal to accelerate the VIPP program.

In its rebuttal testimony, SDG&E states that all parties recommend adopting its 2017 adjusted, recorded capital costs.

16.2.2. Discussion

ORA and CUE raise the same recommendations and supporting arguments concerning use of 2017 adjusted, recorded capital costs and increased capital spending for 2019 respectively, as both parties did in the SoCalGas section. We make the same findings and conclusions as discussed in section 16.1.4. above.

Regarding TIMP and DIMP capital costs for 2017, we find that the testimony and other evidence submitted by SDG&E adequately supports the 2017 forecast but there is little evidence submitted in this application to support the 2017 recorded spending which is more than \$12.592 million higher than the 2017 forecast. In any case, as with SoCalGas, SDG&E's TIMP and DIMP costs are subject to a two-way balancing account treatment through the TIMPBA and DIMPBA respectively. Amounts above 35 percent will be subject to a separate application procedure. Under this recovery process, SoCalGas should be able to appropriately explain and provide information regarding spending incurred. Similarly, the recovery process for SDG&E's TIMP and DIMP are the same as SoCalGas, where undercollections will be limited to amounts up to 35 percent of the total revenue requirement for that program and will require a Tier 3 advice letter. Under this recovery process, SDG&E will be provided with the appropriate safety spending and should be able to appropriately explain and provide information regarding the spending.

Similarly, with regards to CUE's recommendations concerning accelerated replacement rates for the VIPP and DREAMS programs, we find as we did in the SoCalGas section that there are other key pressing safety risks that must be addressed and that costs for these programs must also be prioritized and balanced with keeping rates affordable. However, we also find that SDG&E should include an outlook of its long-term assessment and replacement plan of its Aldyl-A pipes and the DREAMS program pipe replacement in its next GRC, in addition to what it plans for the next GRC cycle as it appears that its current replacement rate is not on pace with its original assessment.

Based on our review and analysis, we find it reasonable to authorize SDG&E's requested amounts of \$11.00 million for O&M costs and capital costs of \$24.216 million each for 2017 and 2018, and \$49.00 million for 2019.

17. Pipeline Safety Enhancement Plan (PSEP)

On September 9, 2010, a 30-inch diameter natural gas pipeline ruptured and caught fire in San Bruno, California, causing death and property damage.¹⁵⁶ As one of its responses to this incident, the Commission initiated R.11-02-019 to consider what aspects of the Commission's regulation of natural gas transmission and distribution pipelines should change. In D.11-06-017, the Commission required operators of natural gas pipelines to file a comprehensive Implementation Plan to replace or pressure test all-natural gas transmission pipeline in California that have not been tested or for which reliable records are not available.¹⁵⁷ D.11-06-017 also provided specific requirements that must be

¹⁵⁶ R.11-02-019 at 1.

¹⁵⁷ D.11-06-017 at 23 to 24.

complied with. These were later codified under Pub. Util. Code Sections 957 and 958.

The Commission authorized SoCalGas' and SDG&E's safety enhancement plan in D.14-06-007 and directed the utilities to begin implementation of the plan. However, the Commission did not pre-approve the proposed budget for the plan and instead developed a review and recovery mechanism wherein costs for individual projects can be approved after-the-fact.¹⁵⁸ The decision also clarified that the utilities may alternatively file for preapproval of specific projects seeking approval of a cap or for other specific guidance.¹⁵⁹ Subsequently, the Commission authorized SoCalGas and SDG&E in D.16-08-003 to include in their TY2019 GRC all PSEP costs not subject to prior applications including possible review of any remaining 2018 Phase 1A and 1B capital costs.¹⁶⁰ This GRC is the first that includes any PSEP costs.

The primary objectives of PSEP are to enhance public safety, comply with Commission directives, minimize customer impacts, and maximize cost effectiveness of safety investments. PSEP is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B.

Phase 1A includes pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in HCAs¹⁶¹ that do not have sufficient documentation of a

¹⁵⁸ D.14-06-007 at 60 to 61.

¹⁵⁹ *Id.* at 61.

¹⁶⁰ D.16-08-003 at 16.

¹⁶¹ With respect to natural gas, HCAs are specific locales and areas where a release could have the most significant adverse consequences.

pressure test to at least 1.25 times the maximum allowable operating pressure (MAOP). The different classes are defined by the DOT's definition of location class which is based on levels of population density within a fixed distance from a natural gas pipeline. Generally, Class 1 and 2 locations are located in unpopulated areas.

The scope for Phase 1B includes the replacement of non-piggable pipelines installed prior to 1946. Non-piggable pipelines are those that cannot accommodate in-line inspection tools that assess pipeline integrity.

Phase 2A addresses transmission pipelines that do not have sufficient documentation of a pressure test to at least 1.25 times the MAOP located in class 1 and 2 locations that are in non-HCA areas.

Phase 2B pipelines are those that have documentation of a pressure test that predates the adoption of federal testing regulations in 1970, specifically, Part 192 Subpart J of Title 49 of the CFR. Prior to this date, the applicable industry standard was American Standards Association B31.8, which came into effect in 1955. No Phase 2B projects are included in this GRC but parties seek clarification regarding these pipelines and the Scoping Memo determined that the interpretation of D.11-06-017 regarding pressure testing of pipeline segments in accordance with the Subpart J standard is within the scope of the proceeding.

Summary of Requested Costs

All costs requested for PSEP are for SoCalGas and total \$249,467,456 for O&M and \$649,326,239 for capital. The above amounts will cover funding for 11 pressure test projects, 11 replacement projects, and 284 valve bundle projects in furtherance of continuing to implement its authorized PSEP. All the requested funds are RAMP-related to mitigate a top safety risk identified in the RAMP Report namely, Catastrophic Damage Involving High-Pressure Pipeline Failure.

Pursuant to D.16-06-054, costs relating to the Aliso Canyon gas leak incident have been excluded from the TY2019 forecasts and from historical information used by impacted GRC witnesses. Efficiencies relating to FOF have been factored into the PSEP cost estimates.

17.1. Pressure Test Projects

This section contains the requests related to 11 pressure test projects as part of the ongoing implementation of PSEP. The total amounts requested are \$236.379 million for O&M costs and \$64.443 million for capital costs. According to SoCalGas, because 2019 is a transition year as PSEP is incorporated into the GRC process, costs presented represent the total costs over the three-year GRC period and not just for the TY.

Certain costs already incurred from the planning and engineering of these projects prior to 2019 are included in the Pipeline Safety Enhancement Plan - Phase 2 Memorandum Account. SoCalGas will seek amortization of this memorandum account in a separate proceeding as authorized under D.16-08-003.¹⁶² SoCalGas also adds a request for five additional pressure test projects in the 3rd PTY (2022) if the request for an additional attrition year is approved in this decision.

SoCalGas describes the method for developing the project estimates in Exhibit 231.¹⁶³ These activities include planning, engineering design, input from subject matter experts regarding project cost estimates, analysis of environmental

¹⁶² Exhibit 231 at RDP-A-21 and D.16-08-003 OP 1 at 14 to 15.

¹⁶³ Exhibit 231 at RDP-A-23 to 27.

impacts, inputs regarding construction, determination of required permits, analysis regarding natural gas loads, and supply management.

The table below presents a breakdown and summary of the 11 pressure test projects included in this GRC. All projects are Phase 2A projects and all costs were forecast using a zero-based methodology.

Pressure Test Projects	Mileage	O&M	Capital	Total
235 West Section 1 - San Bernardino County	24.6	\$41,642,000 ¹⁶⁴	\$12,106,000	\$53,768,000
235 West Section 2 - San Bernardino County	20.3	\$25,679,000	\$11,181,000	\$36,860,000
235 West Section 3 - San Bernardino County	26.9	\$14,119,000	\$3,370,000	\$17,489,000
407 - Santa Monica Mountains	4.0	\$4,188,000	\$962,000	\$5,150,000
1011 - Ventura County	1.8	\$4,421,000	\$746,000	\$5,167,000
2000 Chino Hills - Orange/Riverside County	10.0	\$33,964,000	\$11,371,000	\$45,335,000
2000 Section E - Riverside County	8.9	\$13,955,000	\$1,565,000	\$15,520,000
2000 Blythe to Cactus City Hydrotest - Riverside County	64.7	\$39,937,000	\$11,908,000	\$51,845,000
2001 W Section C - Riverside County	13.9	\$22,868,000	\$3,361,000	\$26,229,000
2001 W Section D - Riverside County	17.8	\$24,404,000	\$4,873,000	\$29,277,000
2001 W Section E - Riverside County	8.9	\$11,182,000	\$3,000,000	\$14,182,000
Total		\$236,379,000	\$64,443,000	\$300,822,000

¹⁶⁴ This amount was revised but the total amounts do not include the change.

Descriptions of each pressure test project are provided in Exhibit 231. Most of the details are similar in nature depicting the pipeline length, location, the number of test sections, and elevated areas. Capital cost descriptions are also similar in nature describing the number of sections of pipeline to be replaced to remediate anomalies and to facilitate hydrotesting. SoCalGas' workpapers for this section include more specific details for each project presenting more detailed scope, individual test sections, and a map of the area covered by the projects.

17.1.1. Positions of Intervenors

ORA developed statistical models for PSEP pressure test and replacement projects based on up to five years of historical cost data from projects by PG&E, SoCalGas, SDG&E, and Southwest Gas Company.¹⁶⁵ ORA's statistical models use linear regression analysis to produce an equation that describes how costs relate to certain project factors. The model uses a 90 percent threshold level which means that there is a 90 percent probability that a future project will be at or below the cost threshold established. The majority of the data uses early Phase 1A data projects from PG&E and SoCalGas that are located in more urban areas and which are shorter in length. The model also assumes cost improvement over time. This model is the same model recommended by ORA in A.17-03-021 but was updated to include more recent pressure test and pipe replacement data. ORA did not apply the model to four pressure tests and two replacement projects¹⁶⁶ with longer pipeline mileage and considered these as

¹⁶⁵ *Id.* at 23 to 24.

¹⁶⁶ The model was also not applied to 4 projects scheduled for the 3rd PTY which the decision is not considering as the request to include a 3rd PTY is being denied.

outside the model's range. ORA does not recommend costs for these in the interest of applying the model conservatively.

TURN, SCGC, Lancaster, and IS recommend disallowance of the risk assessment component which equals to a reduction of \$63 million using TURN's and SCGC's calculation and a reduction of \$58.6 million using IS' calculation.

17.1.2. Discussion

We carefully reviewed and analyzed ORA's proposed model and the method utilized by SoCalGas as well as the comments from the other intervenors. Although we find merit in ORA's proposed model and while ORA's model provides a foundation for per mile averages that may be used in the future as the data becomes more refined, we find that SoCalGas' project-specific evidence is more appropriate for the pressure test and capital projects being proposed in this decision.

ORA's model is based on using data from past projects to predict costs for future projects. However, the model relies on general project data such as pipeline length and diameter and project duration but does not apply factors surrounding a particular project that may be specific to certain types of projects or even a specific project only. Most of the data uses early Phase 1A projects whereas the projects proposed in this application are Phase 2A and Phase 1B projects. Also, 95 percent of the pressure test data are from PG&E PSEP projects¹⁶⁷ and does not account for project differences between different utilities. ORA's pressure test data also only applies O&M costs whereas the Pressure Test Projects include both an O&M component and a capital component. The model

¹⁶⁷ Exhibit 235 at RDP/SC-15 to 16.

also does not specifically apply other factors such as elevation, terrain, and other geographic conditions as well as the need to bypass private lands, the types of permits and environmental clearances that are necessary, the engineering design of a project, and other factors that may be relevant. Lastly, the model is not applied to certain projects that fall out of range, which may lead to inconsistencies if it is applied to some projects while SoCalGas' method is applied to projects that are considered outside the model's range.

On the other hand, SoCalGas applies a more project-specific method to develop its forecast costs, which we find more appropriate in this instance and for the proposed projects specifically. SoCalGas provided what is referred to under the American Association of Cost Engineers (AACE) cost estimate classification system as Class 3 estimates for its proposed projects using around a 30 percent completion of engineering activities. SoCalGas explains that according to the AACE classification system, Class 3 estimates are generally prepared to form the basis for budget authorization or funding and typically form the initial control estimate against which all actual costs and resources will be monitored.¹⁶⁸ Engineering is typically from 10 to 40 percent complete. This level of estimate contains more specific details and is generally more reliable than Class 4 and Class 5 estimates that are based on more limited information.

As discussed earlier, SoCalGas' method for developing its project estimates included planning, engineering design, input from subject matter experts regarding project cost estimates, analysis of environmental impacts, inputs regarding construction, determination of required permits, analysis

¹⁶⁸ Exhibit 238 at RDP/SC-7.

regarding natural gas loads, and supply management. The above activities are more project-specific and take into account specific circumstances regarding each project. This level of detail allows us to better evaluate and review costs requested consistent with D.14-06-007, where the Commission stated that ratepayers should have the benefit of detailed plans for the Commission to consider before authorizing or pre-approving expenditures for PSEP projects.¹⁶⁹

Cost estimates were developed using a zero-based method, which we find reasonable in this instance as specific needs for each project are better taken into account and incorporated into the forecast as opposed to basing costs on budget history.

Based on all of the above, we find SoCalGas' method and cost estimates to be reasonable, appropriate for the proposed projects, and supported by the testimony submitted.

Risk Assessment Component

SoCalGas' project cost estimates include a risk assessment component following a recommended practice from the AACE. This recommended practice is based on the premise that unforeseeable events that occur lead to additional costs, and project managers have a tendency to underestimate the cost of a project. This contingency factor is reflected as a percentage of the forecasted cost of a project. The appropriate level or amount is determined by subject matter experts who examine and weigh the risks and contingencies surrounding each specific project.

¹⁶⁹ D.14-07-007 at 23.

For its proposed PSEP projects, SoCalGas' contingency amounts ranged from 18 percent to 33 percent with Pressure Test Projects averaging 26 percent and Replacement Projects averaging 25 percent.

We agree with the addition of a risk assessment component in this instance to account for contingencies that may occur. The proposed projects are subject to many variables and projects have particular circumstances that add to the difficulty of making accurate cost estimates. The practice is also an industry-recommended practice that aims to increase the quality and accuracy of estimates, which we find appropriate for the proposed PSEP projects.

However, we share TURN/SCGC's concerns that SoCalGas' contingency factors overinflate the overall costs given SoCalGas' detailed project cost estimates. We find that more conservative contingency estimates are appropriate in this instance as the proposed Phase 2A Pressure Tests Projects and Phase 1B Replacement Projects are subject to a lesser degree of unpredictable variables relative to the earlier Phase 1A projects. SoCalGas also has more data from the earlier PSEP projects within which to make more informed and more detailed forecasts. According to SoCalGas, information from AACE shows that a contingency range of 15 percent to 30 percent is appropriate for these types of projects.¹⁷⁰

Based on the above circumstances, we find that a contingency factor at the lower range provided by AACE or an average of around 15 percent is more reasonable in this case. Therefore, we find that SoCalGas' total forecast for the 11 Pressure Test Projects identified in this section should be approved subject to a

¹⁷⁰ Exhibit 235 at RDP/SC-29.

10 percentage points reduction to the risk assessment component of each project. In addition, as discussed later in Section 17.6, we find it reasonable to authorize the establishment of a PSEP memorandum account to track possible cost overruns for recovery in SoCalGas' next GRC filing.

At this time, we also wish to highlight the Commission's significant concerns regarding SoCalGas' Line 235, currently scheduled for pressure testing during this GRC period. On October 1, 2017, a rupture occurred on Line 235. As SoCalGas sought to bring Line 235 back into service, numerous leaks have been found in the pipeline. The line is currently out of service as of the date of this proposed decision. In part because of this highly concerning pattern of leaks on Line 235, in June 2019 the Commission opened an investigation into SoCalGas' safety culture.¹⁷¹ As noted by SoCalGas' witnesses, the repairs to Line 235 may be included in TIMP over the next rate case cycle¹⁷² and may also impact the scheduling of the pressure testing of the line.¹⁷³ We understand TURN/SCGC's concerns that the repaired segments on Line 235 will be accounted for both in TIMP and PSEP, but we find it reasonable that the small non-contiguous portions of the rupture cannot be easily removed from the continuous pressure testing as it would not be cost-effective.

Given the numerous issues and uncertainty related to Line 235 and the safety aspects to the repairs and the testing, we support immediate corrective actions. However, we require SoCalGas to file a Tier II Advice Letter at the

¹⁷¹ I.19-06-014.

¹⁷² SCG-SDG&E Opening brief, p. 134.

¹⁷³ Exhibit 231 at RDP-A-56.

conclusion of the Line 235 West Sections 1 and 2 testing or replacement with clear accounting delineations of which costs are subject to TIMP and which costs are subject to PSEP before any of the associated costs can be placed into rates for recovery. Such PSEP costs shall not be placed into rates for recovery and such TIMP costs shall be made subject to refund until the Advice Letter is approved. The Line 235 costs subject to this accounting requirement should include costs SoCalGas is incurring for the additional permits, crews, environmental monitoring, and all other costs associated with investigating and repairing the ongoing leaks on Line 235.

Costs to repair the rupture and leaks to Line 235 are not requested in this GRC but we find it reasonable to require SoCalGas to establish a memorandum account to record all costs related to Line 235 (i.e., capital costs including rate of return, operations and maintenance costs, repair and replacement costs, or any other costs related to the line). This memorandum account will allow the Commission the future ability to adjust SoCalGas' TY2019 revenue requirement for TY2019 and PTYs 2020 and 2021 should a future inquiry find that Line 235 is no longer used and useful and if costs relating to Line 235 are unreasonable.

17.2. Miscellaneous PSEP Costs

The table below shows the estimates for Miscellaneous Costs relating to PSEP.

Miscellaneous Costs	O&M	Capital	Total
Allowance for Pipeline Failures	\$0	\$6,170	\$6,170,000
Implementation Continuity Costs	\$3,741,000	\$1,857,000	\$5,599,000
Program Management Office	\$11,831,000	\$29,606,000	\$41,438,000
Total	\$15,573,000	\$37,634,000	\$53,206,000

17.2.1. Allowance for Pipeline Failures

Costs associated with a pipeline test failure primarily consist of replacement costs of the failed pipe segment and costs relating to water containment following the failed test. No O&M costs are projected as there has only been one incidence of a test failure out of 53 separate tests covering 90 miles of pipeline. The forecast represents an allowance of three test failures for the GRC period.

17.2.2. Implementation Continuity Costs

These costs include environmental permitting and land acquisition for approximately seven projects anticipated in the next GRC. These costs are requested now because of the length of time and advance preparation needed to obtain necessary permits to ensure that the projects planned for the next GRC cycle to ensure that the projects are completed in a timely manner.

17.2.3. Program Management Office

These costs represent General Management and Administration (GMA) costs and company overhead costs incurred in support of PSEP that are not charged to individual projects. Beginning in 2019, these costs will be accumulated into the Project Management Office (PMO). The PMO will provide oversight at the organizational level and develop reporting metrics to keep management apprised of PSEP progress. The PMO will also provide functional guidance on project design and construction to ensure that compliance requirements are met and best practices are applied. The PMO will also develop standards and procedures so PSEP projects are executed in a consistent manner across projects.

17.2.4. Discussion

ORA recommends that Allowance for Pipeline Failures be denied if the two-way balancing account treatment for the PSEP Balancing Account (PSEPBA)

is authorized. We find however, that it is not necessary to rely on balancing account treatment of Allowance for Pipeline Failures as the costs can be forecast with a high degree of certainty based on the frequency of test failures that have occurred to date, which is one test failure for every 90 miles. We also find the estimate for test failure occurrences to be conservative and reasonable.

We also find the estimated amounts for Implementation Continuity Costs and the PMO to be reasonable and supported by the evidence. Implementation Continuity Costs will ensure that the permit process begins without having to wait for approval of SoCalGas' next GRC, which supports the timely completion of projects planned for the next GRC. PMO costs will simply replace GMA costs that were incurred prior to this GRC as those costs will now be accumulated into the PMO. In addition, the PMO will provide needed oversight to help ensure that projects are executed in a consistent, safe, and cost-effective manner.

Based on the above, we find that the requested Miscellaneous Costs totaling \$53.206 million for both O&M and capital are reasonable and should be approved.

17.3. Capital Projects

Capital Projects consists of Replacement Projects and the Valve Enhancement Plan.

17.3.1. Replacement Projects

This section discusses the 11 replacement projects that are planned by SoCalGas in this GRC cycle. The total cost of these 11 projects is estimated at \$301.250 million. SoCalGas also requests an additional two replacement projects and the remaining 50 percent of the 44-1008 replacement project if the request to include a 3rd PTY is approved.

Many of these projects are expected to be completed in 2020 and 2021 and SoCalGas proposes that PSEP capital-related costs not fully reflected in the TY2019 revenue requirement be included as part of the PTYs. SoCalGas states that majority of PSEP capital expenditures are expected to close to plant in service in 2020 and 2021 and these PSEP capital costs will not be fully reflected in the TY2019 revenue requirement. SoCalGas' PSEP capital-related revenue requirement increases proposed in the PTYs are \$13.7 million for 2020, \$34.4 million for 2021. SoCalGas also proposes an increase of \$41.6 million for 2022 but as discussed in section 17.4 below, costs in 2022 are not included in this GRC.

The table below presents a breakdown and summary of the 11 replacement projects included in this GRC. All projects are Phase 1B projects except for the last project, the 200-E Cactus City Compressor Station project which is a Phase 2A project. All costs were forecast using a zero-based methodology.

Replacement Projects	Phase	Mileage	Capital
85 Elk Hills to Lake Station – San Joaquin Valley	1B	13.0	\$88,906,000
36-9-09 North Section 12 – Santa Barbara County	1B	0.9	\$9,813,000
36-9-09 North Section 14 – Santa Barbara County	1B	1.9	\$19,980,000
36-9-09 North Section 15 – Santa Barbara County	1B	1.5	\$14,193,000
36-9-09 North Section 16 – Santa Barbara County	1B	2.0	\$18,036,000
36-1032 Section 11 – Santa Barbara County	1B	0.5	\$8,692,000
36-1032 Section 12 – Santa Barbara County	1B	5.2	\$26,601,000
36-1032 Section 13 – Santa Barbara County	1B	3.2	\$17,811,000
36-1032 Section 14 – Santa Barbara County	1B	1.7	\$13,937,000
44-1008 (50%) ¹⁷⁴ – Central California	1B	54.9	\$76,582,000
2000-E Cactus City Compressor Station – Riverside County	2A	883 feet	\$6,698,000
Total			\$301,250,000

An overview of each of the 11 replacement projects is included in Exhibit 231.¹⁷⁵ Most of the descriptions are similar in nature with pipes of varying vintages from the 1920s to 1940s being replaced to address anomalies, facilitate hydrotesting, or to minimize impacts to private property owners and existing farmland. SoCalGas also describes the activities conducted in developing the project estimates, which include assessment of project parameters, site visits, development of preliminary designs, identification of

¹⁷⁴ SoCalGas intends to complete 50 percent of this project by 2021.

¹⁷⁵ Exhibit 2313 at RDP-A-42 to 47.

waterways, major highways, and railroads, surveys and preparation of base maps, and analysis of environmental restrictions and concerns.

17.3.2. Valve Replacement Plan

SoCalGas is projecting a total of \$246.000 million for 284 valve bundle projects at various locations. The Valve Enhancement Plan is meant to comply with the Commission's directive in D.11-06-017 to include plans for automated or remote controlled shut-off valves as part of SoCalGas' Implementation Plan. The Valve Enhancement Plan enables automatic shut-off and remote control capability at intervals of eight miles or less and enhances system safety by improving existing valve infrastructure and accelerating the ability to identify, isolate, and contain escaping gas in the event of a pipeline rupture.¹⁷⁶ The Valve Enhancement Plan also focuses on isolating transmission pipelines in Class 3 and 4 locations and Class 1 and 2 HCAs. Detailed information regarding specific projects are included in SoCalGas' workpapers.

This GRC application includes valve projects that are projected to begin construction in 2019 and completed by 2021. Cost recovery for valve projects that were in construction prior to 2019 are to be included in another application.

17.3.3. Positions of Intervenors

ORA recommends using its own model that was discussed in the Pressure Test section to evaluate 10 of the 14 capital projects proposed. Applying ORA's model results in a reduction of \$3.8 million to SoCalGas' forecast.

TURN, SCGC and IS recommend disallowance of the risk assessment component for the projects which equals to a disallowance of \$55.5 million using

¹⁷⁶ *Id.* at RDP-A-14.

TURN's and SCGC's calculation and equals \$49.7 million using IS' calculation. TURN and SCGC also recommend that costs of \$76.6 million for Line 44-1008 be disallowed, except for \$0.7 million for permitting costs, because there is no possibility that the project will be completed in this GRC cycle. SoCalGas does not contest this assertion regarding timing for completing the 44-1008 project but argues that the project can be substituted via the substitution process that it is proposing and adds that projects should be completed as soon as practicable.

For the Valve Replacement Program IS recommends that the schedule for completion of the Valve Replacement Plan be extended to six years instead of the three years proposed by SoCalGas. IS also recommends that the risk adjustment component for the project be removed, which it calculates at \$42.2 million.

17.3.4. Discussion

ORA's proposed model and disallowance of the risk assessment component were addressed in our discussion of the Pressure Test Projects in section 17.1.2 and we make the same findings and conclusions as we did there: SoCalGas should reduce the risk assessment component for each project by 10 percentage points, resulting in an average risk assessment component of 16 percent.

Regarding Line 44-1008, we find that the project substitution process should be utilized more as an exception rather than as a standard method of substituting in a requested project that SoCalGas knows is delayed and will not be completed within this GRC cycle. Our primary objective should be to fully review proposed projects and should only allow project substitution in cases when it is necessary and prudent to do so. In this case, the environmental permitting process relating to the project may preclude SoCalGas from even initiating construction during this rate case cycle. In addition, we find that the

project may be better reviewed, analyzed, and evaluated as a whole project rather than the 50 percent of the entire project that is proposed here. In any case, because it is almost certain that the 50 percent project completion proposed here will not be completed in this GRC cycle, we find it more reasonable that authorization for this project be requested in SoCalGas' next GRC application. This results in a reduction of \$76.6 million. In the event that SoCalGas initiates the environmental review for Line 44-1008 during this rate case period, SoCalGas may include the associated costs in the PSEP memorandum account authorized in this section for review in its next GRC filing.

We also note the filing of A.19-04-003 in April 2019, which is PG&E's request for authorization to sell its transmission Line 306 to SoCalGas. In a statement of support for PG&E's application, SoCalGas submitted a formal response stating that the purchase of Line 306 will save ratepayers money and cause less environmental impacts compared to replacing parallel Line 44-1008. We make no findings or determinations regarding the above proceeding but in keeping with the Commission directive to complete PSEP projects as soon as possible, in the event that a resolution for ensuring the safety of Line 44-1008 occurs during this rate case period, any associated Line 44-1008 costs may also be included in the PSEP memorandum account.

With respect to the Valve Replacement Plan, SoCalGas' Implementation Plan authorized in D.14-06-007 includes the replacement of valves in order to comply with the directive set forth in D.11-06-017¹⁷⁷ that SoCalGas' pipeline systems include automated or remote controlled shut off valves that are

¹⁷⁷ D.11-06-017 OP8 at 30.

necessary to protect the public. Thus, we agree with SoCalGas' assessment that valve replacement is an ongoing activity.

Regarding the specific issue on timing for completion of the project, raised by IS, we find SoCalGas' proposal of completing the project within a three-year timeframe more prudent and in alignment with the Commission's objective that PSEP be completed as soon as practicable. Pub. Util. Code § 957 also requires that remote and automatic shutoff valves be installed as quickly as is reasonably possible. The shut-off valves play an important role in accelerating SoCalGas' ability to identify and isolate sections of pipelines to contain escaping gas in case of a rupture. Based on the above, we find that SoCalGas' proposal for a three-year timeframe for completion of the project should be authorized. With respect to the proposed costs, we find that the risk adjustment component should be reduced by 10 percent consistent with our discussion above regarding this issue. We therefore find that SoCalGas' proposed costs for the Valve Enhancement Project should be approved subject to a 10 percentage points reduction of the risk adjustment component.

To summarize, the proposed costs for 10 of the 11 Replacement Projects are approved subject to a 10 percent reduction of the risk assessment component costs for each project. The Line 44-1008 replacement project is not authorized; however, if SoCalGas does in fact begin project work on Line 44-1008, either associated with environmental review or by receiving Commission approval to purchase PG&E Line 306, those costs may be included in the PSEP memorandum account authorized earlier. SoCalGas' forecast for the Valve Replacement Plan is approved subject to a 10 percent reduction in risk assessment component costs.

We also find SoCalGas' proposal that PSEP capital-related costs not fully reflected in the TY2019 revenue requirement be included as part of the PTYs

reasonable and we approve it. This is because PSEP is being incorporated into the GRC for the first time and timing and completion of the proposed projects should not be delayed. We find the adjustment necessary in order to fully reflect the capital costs we are authorizing but will not be fully reflected in the TY.

17.4. Fourth Year Projects (2022)

SoCalGas included seven projects plus the remaining 50 percent of project 44-1008 for 2022 in conjunction with its request to include a 3rd attrition year in the current GRC. As discussed in section 5 of the decision, we are rejecting SoCalGas' request to change their current three-year GRC cycles into a four-year cycle and so we deny approval of the fourth year PSEP projects as this GRC cycle will only include TY2019 and PTYs 2020 and 2021.

17.5. Project Substitution

SoCalGas requests authority to substitute one or more PSEP projects authorized in this decision with other PSEP projects in the event of a delay in commencing construction of one or more of the authorized projects. SoCalGas states that the substitution of projects will not result in costs exceeding the aggregate amount authorized in this decision. Prior to substitution, SoCalGas proposes to file a Tier 1 advice letter. The advice letter will contain the name and scope of the delayed project, the circumstances that led to the substitution, and identification of the substituted project as well as the scope and estimated costs to complete the substituted project.

ORA recommends modification of the above proposal to allow for more in-depth review of a proposed project substitution. ORA proposes that a requested substitution be addressed through an expedited process and that review be conducted by a working group consisting of Applicants, the Commission's Energy Division, ORA, TURN, OSA, and SED. ORA also

proposes an alternative where projects that are of similar scope and costs be allowed. If the above proposals are not adopted, ORA recommends denial of SoCalGas' project substitution proposal.

In analyzing SoCalGas' request, we must balance two competing factors: completing PSEP as soon as practicable and affording the Commission ample opportunity to review the reasonableness of proposed projects and costs. We understand SoCalGas' concern about accelerating certain projects for safety and reliability reasons or substituting new projects in case of delay so other projects can be commenced. However, we must also consider that the projects authorized in this decision were fully reviewed during the application process while a substituted project would be largely unreviewed.

Based on our analysis, we find SoCalGas' request for authority to substitute one or more PSEP projects authorized in this decision with other PSEP projects in cases of delay or when necessary to do so for safety or reliability reasons should be approved. The procedure to request substitution described above and in SoCalGas' testimony¹⁷⁸ should be followed except that SoCalGas should file the request as a Tier 2 advice letter in order to afford the Commission sufficient opportunity to review the proposal without unnecessarily delaying the process.

17.6. PSEPBA

SoCalGas requests continuation of the 2-way balancing account treatment of PSEP costs for this GRC cycle. CUE supports the request because costs are uncertain while ORA, TURN, and IS oppose SoCalGas' request.

¹⁷⁸ Exhibit 231 at RDP-A-56.

ORA states that project cost estimates are well developed and the majority of the estimates contain project contingencies to account for some level of uncertainty of costs. TURN adds that PSEP activities are not fundamentally different from other activities not subject to balancing account treatment and that the PSEP projects proposed in this GRC will be located in more rural areas and subject to less uncertainty. IS adds that the PSEPBA would remove incentive for SoCalGas to manage PSEP costs.

We reviewed the arguments raised by the above parties and agree with ORA, TURN, and IS that PSEP cost estimates for the proposed Phase 2A and 1B projects are better developed relative to Phase 1A projects that have been undertaken by SoCalGas. The currently proposed projects also include project contingencies to address some of the uncertainties as to costs. We also agree with TURN that the proposed projects are located in areas that are less densely populated, which make project costs less uncertain as compared to projects located in more urbanized locations.

Nonetheless, we also recognize that PSEP is a large-scale project which makes costs more difficult to predict. There is also a time lag from when forecasts are made to when the projects will begin and circumstances relied on to develop the forecasts may have change. However, instead of continuing the two-way balancing treatment for PSEP, we find it more reasonable at this later stage of PSEP to authorize the creation of a memorandum account to track potential PSEP overrun costs. We recognize the uncertainty that sometimes occur with construction and given that we are reducing the contingency factors, the memorandum account will allow SoCalGas to track actual costs and request recovery of additional costs that were not foreseen or due to circumstances beyond SoCalGas' control and at the same time afford the Commission sufficient

opportunity to review the reasonableness of additional costs in the next GRC filing. We note that recovery of any costs recorded in the above-mentioned memorandum account shall not be automatically granted but shall instead be subject to a reasonableness review by the Commission.

17.7. Clarification Regarding D.11-06-017

As stated previously in this section, SoCalGas seeks clarification regarding the interpretation of D.11-06-017 regarding pressure testing of pipeline segments that have documentation of a pressure test that predates the adoption of federal testing regulations under Part 192 Subpart J of Title 49 of the CFR. Specifically, SoCalGas seeks clarification whether Phase 2B work covering such pipelines is required to be undertaken and completed.

Ordering Paragraph 4 of D.11-06-017 states provides:

No later than August 26, 2011, San Diego Gas & Electric Company, Southern California Gas Company, Southwest Gas Corporation and Pacific Gas and Electric Company must file and serve a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c). The Implementation Plan should start with pipeline segments located in Class 3 and Class 4 locations and Class 1 and Class 2 high consequence areas, with pipeline segments in other locations given lower priority for pressure testing. The schedule and cost detail for lower priority pipeline segments may be limited.¹⁷⁹

The above passage clearly indicates that all in-service natural gas transmission pipeline be tested in accordance with 49 CFR 192.619, excluding

¹⁷⁹ D.11-07-017.

subsection 49 CFR 192.619 (c). Ordering Paragraph 4 reiterates the same requirement discussed in page 20 of the D.11-06-017.

ORA provides a historical background of pressure standards in Exhibit 398 and explains that 49 CFR 192 came into effect on November 12, 1970 and that prior to this date, the applicable industry standard was American Standards Association B31.8 (ASA Code), which came into effect in 1955.¹⁸⁰

ORA cites to D.15-12-020 to support its position that pipeline segments that had been tested in accordance with the ASA Code need not be re-tested to comply with D.11-06-017. TURN and SCGC support ORA's position.

However, D.15-12-020 resolved an issue concerning cost recovery of re-testing certain pre-1970 pipelines that do not have documentation of test records. The decision held shareholders responsible for maintaining documents of a prior pressure test and thus responsible for the costs of subsequent tests that may be necessary because records of the prior test cannot be produced. On the other hand, the issue before us involves pipelines tested under the ASA Code where documentation of the pressure test exists.

TURN and SCGC add that Ordering Paragraph 4 of D.11-06-017 should be read in conjunction with Ordering Paragraph 3. Ordering Paragraph 3 however, refers to tests conducted prior to the effective date of GO-112 and not specifically to tests conducted prior to the requirements of 49 CFR 192.619.

In analyzing the different positions presented before us, what is most clear is that D.11-06-017 requires that all in-service natural gas transmission pipeline be tested in accordance with 49 CFR 192.619 and the only exclusion that is clearly

¹⁸⁰ Exhibit 298 at 32 to 33.

stated is cases that fall under subsection 49 CFR 192.619 (c). The arguments raised by ORA, TURN, and SCGC as well as the decisions cited by ORA in Exhibit 398 either do not address the issue squarely or do not provide concrete guidance that is clearer than what is provided in D.11-06-017.

Therefore, we conclude that pipelines under Phase 2B of SoCalGas' Implementation Plan must comply with D.11-06-017. At the same time, it is possible that a risk assessment today may find that the risk-spend efficiency of some linear miles of transmission pipeline, particularly in Class 1 locations, is low. To understand conditions on the ground today, and to ensure that compliance with D.11-06-017 occurs in a manner that quantifiably mitigates risk and ensures that funds spent are reasonable for ratepayers, we will require SoCalGas to file a proposed implementation plan for the pipelines that may be re-tested pursuant to this decision. SoCalGas shall file the re-testing implementation plan as part of SoCalGas's 2019 RAMP filing, and the plan shall specifically include the following:

- a. Identification of all in-service natural gas transmission pipelines (by location and including linear feet and the pipelines' categorization in Class locations 1-4) that were tested under the ASA Code and for which test records exist;
- b. Identification of the subset of the above qualifying pipelines for which SoCalGas recommends and does not recommend a re-test, in particular in Class 1 locations in areas that are not High Consequence Areas, and a statement explaining why a re-test is proposed or not proposed;
- c. Presentation of the pre-1970 ASA Code test records for the pipelines proposed to be re-tested, and direct comparison of the test elements shown in the records to the test elements set out in 49 CFR 192.619;
- d. An evaluation by an independent engineer that SoCalGas's proposed determination of which pipelines to re-test or not to re-test is a reasonable engineering judgement;

- e. The forecast costs of re-testing; and
- f. Consistent with the RAMP framework, a complete discussion of the risk-spend efficiency of the dollars proposed to be spent.

18. Procurement

This section discusses SoCalGas' Gas Acquisition and SDG&E's Electric and Fuel Procurement (E&FP) requests. SoCalGas is also requesting \$2.201 million in 2017 and \$0.270 million in 2018 for IT-related capital projects.

18.1. Gas Procurement (SoCalGas)

SoCalGas requests \$4.23 million for Gas Procurement O&M costs for TY2019. The forecast is for costs associated with activities of the Gas Acquisition Department. These costs are non-shared.

The Gas Acquisition Department's primary function is the procurement of reliable natural gas supplies for both SoCalGas' and SDG&E's core customers at a low cost. The Department also procures natural gas for Cap-and-Trade¹⁸¹ emissions compliance instruments for SoCalGas' covered end-use customers and transmission and storage facilities. Gas Acquisition aims to lower carbon emission costs using Commission authorized procurement tools such as: allowance purchases at CARB's quarterly auctions, California Carbon Allowance future purchases, etc. Activities are conducted daily and include negotiation and maintenance of contracts for gas transactions, storage capacity, interstate

¹⁸¹ A cap and trade system is a market-based approach to controlling pollution that allows corporations to trade emissions allowances under an overall cap, or limit, on those emissions. California's Cap-and-Trade program was launched in 2013 and is one of the major policies aimed at reducing greenhouse gas emissions.

transmission capacity, intrastate backbone transmission rights, and carbon emissions compliance instrument procurement transactions.¹⁸²

SoCalGas' testimony includes savings from FOF and excludes costs relating to the Aliso Canyon storage facility gas leak incident.

18.1.1. O&M

The O&M forecast for TY2019 is composed of \$3.867 million for labor costs and \$363,000 for non-labor. Compared to 2016 adjusted, recorded costs, the TY2019 forecast shows an increase of \$267,000 for labor and \$50,000 for non-labor or a total of \$317,000.

Labor costs cover five functional groups that conduct (1) physical gas trading, (2) energy and carbon trading and risk management, (3) gas scheduling, (4) energy economic analysis, (5) finance, administration activities, and IT support. Physical gas traders purchase and trade gas on a daily basis as well but also conduct trades for monthly and long-term basis. Non-labor costs are for subscription fees to industry publications, consultant and online services, training, and travel expenses.

SoCalGas' forecast methodology utilized base year costs as a basis because the Department expects to maintain the same number of positions with the increase representing the cost for filling two vacancies.

18.1.2. IT Business Unit Capital Projects

SoCalGas is also requesting \$2.201 million in 2017 and \$0.270 million in 2018 for two IT-related capital projects. Both projects consist of upgrades to the

¹⁸² Exhibit 282 at MFL-1 to 2.

Pinnacle management application system and will replace the programming language that has become obsolete.

18.1.3. Positions of Intervenors

ORA is the only intervenor to provide comments and recommends a reduction of \$250,000 to SoCalGas' TY2019 forecast. This amount represents a proxy amount for two employee positions:¹⁸³ a director and analyst that SoCalGas plans to be filled. ORA argues that the TY2016 authorized amount included these two positions which were not filled and states that this Department was able to conduct its activities without these two positions.

18.1.4. Discussion

ORA does not object to the increased forecast for TY2019 labor costs and, instead, objects specifically to the need for the two positions that will be filled. However, we find that SoCalGas provided sufficient justification for the two positions identifying increased activities for the Gas Acquisition Department including Cap-and-Trade related labor and administrative costs which were originally charged to GHG activities. SoCalGas also identified increased monitoring and analytical work, anticipated procurement of renewable natural gas, and activities to maximize storage injections for system reliability and ORA did not question these increased activities. We find that level of activities for TY2019 differ from base year 2016 and find that this sufficiently justifies the need for the two positions. With respect to the increased costs compared to base year levels, we find these to be reasonable incremental adjustments due to escalation

¹⁸³ The actual salaries for the two positions are confidential.

of costs. Based on the above, we find that the O&M forecast of \$4.23 million for TY2019 is reasonable and should be authorized.

We reviewed the request for the two IT projects and find the request reasonable and should be approved. No party objected to SoCalGas' proposed projects.

18.2. Electric and Fuel Procurement (SDG&E)

SDG&E is requesting \$8.641 million for E&FP O&M expenses for TY2019. These costs are non-shared. The TY2019 forecast represents an increase of \$679,000 from base year 2016 adjusted, recorded expenses.

E&FP is responsible for planning, procuring, managing, and administering the energy supply resources needed to deliver safe and reliable energy to customers.¹⁸⁴ The actual costs to procure electricity supply are forecasted in the Energy Resource Recovery Account (ERRA) proceeding but E&FP's O&M costs are included in the GRC.

SDG&E is also requesting \$3.005 million in 2017 and \$0.426 million in 2018 for capital projects necessary to maintain compliance with CAISO scheduling services and for Sarbanes-Oxley compliance.

18.2.1. O&M

O&M costs are composed of Long-Term Procurement, Trading & Scheduling, and Middle and Back Office.

18.2.1.1. Long Term Procurement

Long Term Procurement consists of functions by a VP that oversees eight different departments and activities of the Origination and Portfolio Design

¹⁸⁴ Exhibit 285 at KKH-1.

department. The Origination and Portfolio Design department is responsible for soliciting energy supplies to meet long-term energy and capacity requirements. The department also participates in regulatory proceedings and interacts with many government agencies in order to develop plans and implement regulatory mandates.

The forecast for Long Term Procurement for TY2019 is \$2.203 million using a five-year historical average. This includes both labor and non-labor costs.

18.2.1.2. Trading & Scheduling

Trading and scheduling covers activities conducted by the Energy Supply & Dispatch department which include electric procurement and trading, market analysis, electric fuels, and market operations. Generally, this department is responsible for planning, procurement, and trading for short-term transactions or transactions within a five-year time frame.

The forecast for this cost category is \$2.949 million using a five-year historical average. This also includes both labor and non-labor costs.

18.2.1.3. Middle and Back Office

Middle-Office and Back-Office contain activities performed by the Energy Risk Management department and the Settlements and Systems department.

The Energy Risk Management department performs functions such as identifying, managing, monitoring, and reporting market, credit, financial, and operational risks relating to E&FP activities. This department also assesses credit exposure for various contracts and transactions.

The Settlements and Systems department is responsible for financial and accounting activities required to reconcile all energy contracts for power procurement and to verify California Independent System Operator (CAISO) requirements. The department also reviews daily CAISO charges and invoices

for accuracy and is responsible for administration of vendor contracts associated with software subscriptions and software systems used in gas and power transactions.

The forecast for Middle and Back Office is \$3.489 million using a five-year historical average which includes both labor and non-labor costs.

18.2.2. IT Business Unit Capital Projects

SDG&E is requesting \$3.005 million in 2017 and \$0.426 million in 2018 for capital expenditures to support technology upgrades required to maintain its obligation to provide scheduling services within the CAISO market. Specifically, the upgrades are for new software modules and configuration changes to software applications necessary for communication with the CAISO system. Another project is for maintaining systems up-to-date for Sarbanes-Oxley compliance.

18.2.3. Discussion

We reviewed SDG&E's forecast as well as the testimony submitted. We find that the requested activities have been normally and regularly conducted by E&FP and funded in prior GRCs. We find these activities to be necessary to carry out the functions performed by E&FP. With respect to the forecast costs, we find the use of a five-year historical average to be appropriate as the volume for certain activities tend to fluctuate depending on the circumstances as well as need and market conditions. Because of this, a five-year average is appropriate in order to normalize these fluctuations.

Based on the above, we find that the requested O&M costs of \$8.641 million for TY2019 are reasonable and should be approved. ORA is the only other party that provided comments and does not have any issue with SDG&E's forecast.

We reviewed the request for the two IT projects and find the request reasonable and should be approved. No party objected to SDG&E's proposed projects.

19. Advanced Metering Infrastructure

This section covers SoCalGas' AMI implementation costs and discusses how these are incorporated into TY2019 ongoing operations. The section also addresses the Advanced Metering Organization (AMO) required to monitor, operate, and maintain SoCalGas' AMI technology.

The Commission authorized the AMI project in D.10-04-027 along with the Advanced Metering Infrastructure Balancing Account (AMIBA) to record O&M and related capital costs for the AMI project period which was from 2010 to 2017. This timeframe was later modified to include 2018 as a bridge-year period which resulted in the AMIBA also being modified to include a post-deployment phase cost sub account.¹⁸⁵ Integration of the impacts of AMI implementation into SoCalGas' continuing operations and associated GRC forecasts is being conducted for the first time in TY2019.

Certain costs for AMI are associated with RAMP risks identified in the RAMP Report. These RAMP costs are estimated at \$0.456 million and involve mitigation of risks covered in SCG-2 of the RAMP Report involving employee, contractor, customer, and public safety. Specifically, risks being mitigated are activities associated with Gas Consumption Analytics and the Data Collector Unit (DCU) & AMI-installed Pole Inspections.¹⁸⁶ Gas Consumption Analytics

¹⁸⁵ Exhibit 287 at RFG-13.

¹⁸⁶ SoCalGas conducts cyclical inspections of poles that contain AMI and DCU equipment and related materials attached to the poles.

concerns technology that detects unauthorized meter turn-ons by unauthorized persons at premises where technicians have previously turned service off. On the other hand, DCU & Pole Inspections concerns technology that conducts cylindrical inspections of AMI installed on poles and materials and equipment that are attached to these poles.

19.1. O&M Costs

SoCalGas requests \$10.477 million for TY2019 using a zero-based forecast methodology for ongoing support to operate and maintain the AMI network, equipment, systems, and related business processes.

19.1.1. Discussion

Parties do not oppose the requested amount for O&M although EDF recommends that 10 percent of the AMI funding for the AMO be allocated towards mitigating operational and market risks as part of its recommended plan related to “Gas Electric Coordination.” However, we agree with SoCalGas that AMI O&M costs have little connection with the Gas Electric Coordination concept being proposed by EDF. We also find that EDF did not provide supporting evidence and analysis to explain the basis and justification for its recommendation. Therefore, we find that EDF’s proposal should be rejected.

Regarding the requested amount, we find it reasonable and supported by the evidence. Exhibit 287 also includes the projected benefit for TY2019 of AMI to various business areas. Table RG-9¹⁸⁷ shows the estimated O&M and Capital benefits and Table RG-10¹⁸⁸ shows the impact to various business units affected.

¹⁸⁷ Exhibit 287 at RFG-26.

¹⁸⁸ *Id.* at RFG-27.

Parties that reviewed SoCalGas' request including ORA, did not oppose the total amount. We likewise find the use of a zero-based forecast to be appropriate as this is the first year in which AMI O&M expenses are being included in a GRC following completion of deployment and post-deployment activities in 2018. Based on the above, we find that SoCalGas' requested amount of \$10.477 million for O&M costs should be approved.

19.2. Capital

Capital projects planned are Information Technology (IT)-related projects concerning the DCU. The total amounts requested are \$1.768 million for 2018 and \$4.815 million for 2019. SoCalGas is also including capital costs recorded in the AMIBA for 2017 and 2018.

19.2.1. AMI Balancing Account (Capital)

As stated in the opening portion of this section, AMI costs from 2010 to 2018 are tracked in the AMIBA and the balancing account is showing \$24.718 million in 2017 and \$7.524 million in 2018 as capital costs. These amounts are for rate base purposes only and the funds are not being requested in this GRC as the AMIBA was previously authorized in D.10-04-027 and D.16-06-054.

19.2.2. IT Capital Projects

19.2.2.1. DCU LTE Upgrade Program

Each DCU contains a cellular communications card provided by Verizon Wireless or AT&T that relays meter readings and other data back to an end system. The current cards utilize 2G and 3G cellular technology and SoCalGas plans to upgrade these cards and related equipment. The forecast for this program upgrade is \$1.051 million in 2018 and \$4.265 million in 2019.

19.2.2.2. DCU Software IS Upgrade

This project will upgrade information security capabilities of the AMI hardware and IT systems to better defend against cyber attacks. The forecast for this upgrade is \$0.248 million in 2018 and \$0.316 million in 2019.

19.2.2.3. DCU Compliance Inspection Work Management

SoCalGas is proposing to transition its current AMI management system from the 3rd party Sierra application to the SAP asset management system. The management system manages the DCU, poles, compliance inspections, installations, replacements, incidents, and inventory and the SAP system will enhance the technology being utilized and aims to improve system performance. The forecast for this project is \$0.469 million in 2018 and \$0.234 million in 2019.

19.2.3. Positions of Intervenors

ORA proposes disallowance of capital costs for curb meter installation and CUE has proposals concerning annual replacement rate and failure rate of AMI module replacements. These proposals will be discussed and addressed in our discussion of Customer Services Field issues.

19.2.4. Discussion

The amounts recorded in the AMIBA have already been authorized in D.10-04-027 covering AMI costs from 2010 to 2017 and in D.16-06-054 which authorized AMI post-deployment activities in 2018. Thus, it is proper to include these capital amounts for calculating rate base in TY2019.

With respect to the IT-related capital projects, we find all three projects to be necessary. We agree with SoCalGas that it is necessary to upgrade the 2G and 3G cellular cards contained in the DCU to allow faster and more reliable transmission of meter readings and information. Also, according to SoCalGas, the 2G and 3G cards will no longer be supported by Verizon Wireless and AT&T

making the upgrades necessary. For the software upgrade, we find that upgrading IT security is a continuous process that occurs periodically and that such is necessary in order to provide adequate protection against attacks that are becoming more sophisticated over time. Finally, we find the proposed transition into the SAP system to be reasonable as part of SoCalGas' and also SDG&E's efforts to convert dated systems into more modern systems that can accommodate new technology and meet regulatory and customer needs that are becoming more complex. We also find that amounts requested for the IT projects are reasonable and supported by the evidence. Based on the above, we find that the requested amounts for capital projects totaling \$1.768 million for 2018 and \$4.815 million for 2019 should be approved. We also find that it is proper to include the AMIBA balances of \$24.718 million in 2017 and \$7.524 million in 2018 for rate base purposes.

20. Electric Generation

SDG&E's Electric Generation request encompasses four primary areas: Generation Plant; Administration; San Onofre Nuclear Generating Station (SONGS) O&M; and Resource Planning.

The total forecast for TY2019 is \$63.411 million which is \$26.229 million higher than base year levels. This is inclusive of \$2.478 million in savings from FOF which include goods and services benefits, water treatment and usage programs, optimizing the maintenance frequency of gas turbines, and installing plant cycling damage monitoring and diagnostics tools. For Capital Costs,

SDG&E's forecast is \$13.314 million¹⁸⁹ for 2017, \$292.826 million in 2018, and \$17.371 million for 2019. The 2018 costs include \$280.00 million to purchase the Otay Mesa Energy Center (OMEC).¹⁹⁰

Certain costs included in this section are RAMP-related costs supporting activities that mitigate key risks identified in the RAMP Report. The key risk being mitigated is failure to black start.¹⁹¹ RAMP-related costs are estimated at \$40,000 O&M and \$1.106 million in capital costs. Risks related to Electric Generation are generally related to safety, system reliability, site security and cybersecurity, natural disaster, and recovery from grid outages.

20.1. Non-Shared O&M Costs

Non-shared O&M costs include costs related to Generation Plant, Administration, and SONGS. The total forecast for TY2019 is \$62.316 million which is \$25.881 million higher than 2016 costs. Most of the increase is due to the addition of OMEC which accounts for \$22.796 million of O&M costs.

20.1.1. Generation Plant

The Generation Plant group owns and operates four electric generation plants as follows:

¹⁸⁹ Revised from \$13.314 million to \$12.807 million in the Update Testimony (Exhibit 514) at Attachment I.

¹⁹⁰ OMEC is a wholly owned indirect subsidiary of Calpine Corporation and it's the owner of the Otay Mesa generation plants. In this section, OMEC and the Otay Mesa plant are sometimes used interchangeably when referring to what SDG&E will acquire pursuant to the Put Option exercisable by OMEC.

¹⁹¹ A black start is the process of restoring an electric power station or part of an electric grid back to operation without relying on the external electrical power transmission network to recover from a total or partial shutdown.

- a. Palomar Energy Center (Palomar), a 565 megawatt (MW)¹⁹² plant located in Escondido;
- b. Desert Star Energy Center (Desert Star), 480 MW located in Boulder City, Nevada;
- c. Miramar Energy Facility (Miramar), 92 MW located in San Diego; and
- d. Cuyamaca Peak Energy Plant (Cuyamaca), 45 MW located in El Cajon.

Palomar and Desert Star are combined cycle power plants¹⁹³ while Miramar and Cuyamaca are peaking plants¹⁹⁴ used for peaking duty when there is high demand. Since 2017, SDG&E added two battery energy storage system projects, the Escondido Battery Energy Storage System (Escondido BESS) and the El Cajon BESS, and the Ramona Solar Energy Project (RSEP).

The table below shows the TY2019 forecasts for Generation Plant as well as the 2016 costs.

Generation Plant	TY2019	2016 Costs	Difference
Palomar	\$18,556,000	\$17,583,000	\$973,000
Desert Star	\$15,561,000	\$14,419,000	\$1,142,000
Miramar	\$2,380,000	\$1,414,000	\$966,000
Cuyamaca	\$1,078,000	\$1,369,000	-\$291,000
Otay Mesa	\$22,796,000	\$0	\$22,796,000
Total	\$60,371,000	\$34,785,000	\$25,586,000

Except for the Otay Mesa generation plant, the forecasts for the other four generation plants were developed based on a five-year average. The cost drivers

¹⁹² 565 MW represents the full load at design conditions.

¹⁹³ A combined cycle power plant refers to an assembly of heat engines that work in tandem from the same source of heat, converting it into mechanical energy which in turn powers electric generators.

¹⁹⁴ Peaking power plants generally only run when there is high demand for electricity.

for the four generation plants are also the same with the majority of those costs relating to maintenance outages.

20.1.1.1. Otay Mesa Plant

SDG&E's TY2019 forecast includes costs relating to Otay Mesa, a 608 MW combined cycle power plant located near San Diego. SDG&E had contracted for the use of OMEC through a non-renewable Power Purchase Tolling Agreement (PPTA) from October 3, 2009 to October 2, 2019.¹⁹⁵ The PPTA was authorized by the Commission in D.06-02-031 but was modified by D.06-09-021¹⁹⁶ to include "Put" and "Call" options at the end of the 10-year PPTA.

The Call Option, which is exercisable at SDG&E's sole discretion, would require OMEC to sell the Otay Mesa plant to SDG&E at a price higher than the price in the Put Option. Additional Commission review is necessary prior to exercise of the Call Option. According to a Calpine's Form 10Q filing, the price of Otay Mesa plant under the Put Option is \$280.0 million and \$377 million under the Call Option. Since then, SDG&E has chosen not to exercise its Call Option which has expired.¹⁹⁷

The Put Option is exercisable at OMEC's sole discretion and would require SDG&E to purchase the Otay Mesa plant at a set price that would be significantly below the net book value of Palomar,¹⁹⁸ which is smaller in size. Exercise of the Put Option by OMEC is due no later than April 1, 2019 and requires no

¹⁹⁵ Exhibit 97 at DSB-5.

¹⁹⁶ POC filed a petition to modify D.06-09-021 on November 13, 2018 which was denied by the Commission in D.19-03-012 on March 28, 2019.

¹⁹⁷ Advice Letter 3294-E at 1 filed on October 26, 2018.

¹⁹⁸ D.06-09-021 at 5.

additional Commission review or approval.¹⁹⁹ OMEC only needs to notify SDG&E that it is exercising its Put Option on or before April 1, 2019.

SDG&E expects the Put Option to be exercised and requests authority to establish the Otay Mesa Acquisition Balancing Account (OMABA), a one-way balancing account. The OMABA will record the revenue requirement for the Otay Mesa plant until SDG&E acquires ownership thereof so ratepayers are indifferent to the timing of the actual transfer of ownership or in the event that the PPTA merely expires without the Put Option being exercised. The balancing account would also ensure that no revenue requirement prior to the transfer date of plant ownership or if plant ownership does not occur, would be retained aside from PPTA and equity rebalancing costs.

Otay Mesa costs were developed using Palomar costs as a basis because of their similarities. Estimated plant operation and maintenance costs are shown as non-labor costs because it is still unknown if the Calpine employees currently operating Otay Mesa will be employed by SDG&E.

20.1.1.2. Resolution E-4981

On February 21, 2019, the Commission issued Resolution E-4981 approving SDG&E's request in Advice Letter 3294-E for a proposed Long Form Confirmation for Resource Adequacy Capacity Product (Confirmation) between SDG&E and OMEC for local, system and flexible capacity from the Otay Mesa plant between October 3, 2019 through August 31, 2024. The Confirmation is therefore set to begin immediately after the expiration of the 10-year PPTA between SDG&E and OMEC. According to SDG&E, OMEC intends to relinquish

¹⁹⁹ Exhibit 97 at DSB-5.

its right to sell the Otay Mesa plant through the Put Option once Resolution E-4981 becomes final. SDG&E will then consider its options on how to withdraw its OMEC acquisition related requests in the GRC.²⁰⁰ However, on March 27, 2019, POC filed an application for rehearing of Resolution E-4981 which prompted OMEC to exercise its rights under the Put Option on March 28, 2019 to sell the Otay Mesa plant to SDG&E. In light of this development, SDG&E states that it will commence the pre-ownership due diligence process set forth in the PPTA. On August, 6, 2018, the Commission issued D.19-08-014 denying POC's application for rehearing of Resolution E-4981.

20.1.2. Administration

Administration is composed of Generation Plant Administration and Electric Project Development. Costs were forecast using the base year method because costs are expected to remain at around base year levels. The table below shows the TY2019 forecasts for Administration as well as the 2016 costs.

Administration	TY2019	2016 Costs	Difference
Generation Plant Administration	\$348,000	\$348,000	0
Electric Project Development	\$121,000	\$63,000	\$58,000
Total	\$469,000	\$411,000	\$58,000

Generation Plant Administration

Provides managerial oversight and analytical support for Electric Generation.

²⁰⁰ Resolution E-4981 at 5 to 6.

Electric Project Development

Supports Electric Generation and Resource Planning, Smart Grid Projects, and Distribution Planning.

20.1.3. SONGS

SONGS-related O&M consists of costs for Marine Mitigation and SONGS Worker's Compensation. The table below shows the TY2019 forecasts for SONGS-related O&M costs as well as the 2016 costs.

SONGS	TY2019	2016 Costs	Difference
Marine Mitigation	\$1,015,000	\$946,000	\$69,000
SONGS Worker's Compensation	\$461,000	\$293,000	\$168,000
Total	\$1,476,000	\$1,239,000	\$237,000

SDG&E owns a 20 percent share of SONGS and incurs its share of Marine Mitigation costs from the values determined in SCE's TY2018 GRC. SCE provides its Marine Mitigation forecast in its TY2018 GRC and then bills SDG&E for SDG&E's 20 percent share of expenses.²⁰¹ Costs are tracked in the Marine Mitigation Memorandum Account (MMMA) to ensure that ratepayers only pay for what SCE bills SDG&E. Marine Mitigation costs are incurred for ongoing projects designed to mitigate the turbidity effects caused by the movement of ocean water to cool SONGS when it was operational.²⁰²

SONGS Worker's Compensation

Similar to Marine Mitigation, SDG&E is billed by SCE for its 20 percent share of SONGS Worker's Compensation costs. SCE maintained a Master

²⁰¹ Exhibit 97 at DSB-23.

²⁰² *Ibid.*

Insurance Program (MIP) and a Self-Insured Worker's Compensation Program for SONGS-related accident and injury claims while SONGS was still operating and both programs will remain open until all claims are closed.

SONGS Balancing Account (SONGSBA)

SDG&E is requesting continuation of the two-way SONGSBA which records non-decommissioning SONGS costs billed by SCE.

20.2. Shared O&M Costs (Resource Planning)

The only category under shared services is Resource Planning and the TY2019 forecast for Resource Planning is \$1.095 million which is \$0.348 million higher than 2016 costs. Costs were forecast using a five-year average with an adjustment for incremental costs. Resource Planning is responsible for planning the long-term electric generation needs of bundled customers as well as planning for adequate resources to meet local capacity requirements of all customers.

20.3. Capital

As stated at the beginning of this section, SDG&E's forecast for capital costs is \$13.314 million for 2017, \$292.826 million in 2018, and \$17.371 million for 2019. Costs were forecast using an adjusted five-year average which removes large, one-time capital projects from historical costs. Rather than proposing specific projects, SDG&E proposes to use a general capital budget to allow flexibility and adaptability to meet current and future plant needs. The underlying cost drivers for the capital projects relate to maintaining clean, safe, and reliable operation of SDG&E's Electric Generation plant assets. The table below shows the forecasts for the different project categories.

Capital	2017²⁰³	2018	2019
Capital Tools & Test Equipment	\$275,000	\$275,000	\$275,000
Miramar Energy Facility	\$2,580,000	\$2,580,000	\$2,580,000
Palomar Energy Facility	\$5,351,000	\$5,351,000	\$5,351,000
Desert Star Energy Center	\$3,361,000	\$3,361,000	\$3,361,000
Cuyamaca Peak Energy Plant	\$453,000	\$453,000	\$453,000
South Grid - Black Start CPEP	\$300,000	\$806,000	\$0
OMEC Acquisition	\$0	\$280,000,000	\$0
OMEC Ongoing Capital	\$0	\$0	\$5,351,000
Solar Photovoltaic Plant	\$994,000	\$0	\$0
Total	\$13,314,000	\$292,826,000	\$17,371,000

20.4. Position of Intervenors

ORA, TURN, and POC provided comments to SDG&E's forecasts and requests regarding Electric Generation.

ORA proposes that OMEC costs be removed from the GRC and be addressed at a later time through a Tier 1 Advice Letter filing. ORA also recommends that a reduction of \$1.1 from OMEC O&M costs at the time the Advice Letter filing is made. The reduction corresponds to an adjustment for contracting and procurement efficiencies similar to an adjustment that was applied to Desert Star. ORA also recommends using 2017 adjusted-recorded costs for 2017 instead of the 2017 forecast.

TURN also recommends that OMEC costs be removed from the GRC and be resolved at a later time when uncertainties relating to the OMEC acquisition have been removed. TURN states that the closing date to purchase Otay Mesa, if the sale occurs, would not happen until October 3, 2019 and no OMEC costs

²⁰³ The following 2017 capital forecasts were revised to the following amounts in the Update Testimony (Exhibit 514) at Attachment I: Capital Tools & Test Equipment \$0.119 million, Miramar Energy Facility \$0.738 million, Palomar Energy Facility \$4.438 million, Desert Star Energy Center \$3.394 million, Cuyamaca Peak Energy Plant \$3.791 million, South Grid - Black Start CPEP \$0 million, Solar Photovoltaic Plant \$0.327 million.

would be incurred from January 1, 2019 to October 3, 2019 even though rates would already include OMEC costs of approximately \$51 million if costs for OMEC are approved now.²⁰⁴ TURN adds that the acquisition price for OMEC set at \$280.0 million in the GRC, is also uncertain. TURN does not agree with ORA's recommendation that OMEC costs be addressed via a Tier 1 Advice Letter filing as that process does not provide parties with an opportunity to weigh in on the reasonableness of costs that will be proposed.

TURN also recommends reducing non-OMEC Generation Costs by \$1.878 million as a result of incorporating 2017 data and using a six-year average. For Administration, TURN recommends using a three-year average from 2015 to 2017 resulting in a \$91,000 reduction. For Resource Planning, TURN recommends a reduction of \$0.279 million stating that SDG&E did not provide adequate testimony to justify the additional work that SDG&E claims is needed. Finally, TURN also objects to the inclusion of chamber of commerce dues in O&M costs.

POC states that SDG&E's requests regarding OMEC should be denied with prejudice and that the GRC is typically reserved for determining O&M requests and not acquisition of large-scale plants.²⁰⁵ Alternatively, POC recommends that SDG&E be required to file a separate application to acquire OMEC if the Commission determines in this GRC that denial of OMEC costs is without prejudice.

²⁰⁴ TURN Opening Brief at 51.

²⁰⁵ POC Opening Brief at 29 to 30.

20.5. Discussion

20.5.1. OMEC

First, we disagree with POC that the GRC typically only considers O&M costs and not the acquisition of large-scale plants. The GRC considers O&M and capital costs as well as other requests relating to SDG&E's revenue requirement for the GRC TY and PTYs. This includes capital costs for projects that are of considerable value. There is no limit on the amount or scale of capital projects that may be reviewed. Moreover, this GRC is reviewing the possible OMEC acquisition pursuant to the Put and Call Options that were authorized in D.06-09-021 and we find no need to revisit the reasons for approving the Put and Call Options that were included in the PPTA between SDG&E and OMEC. In Resolution E-4981, the Commission also found that CAISO had determined that OMEC is likely needed for the next five years for local reliability during that period²⁰⁶ and we find no need to re-examine this finding regarding the necessity for OMEC.

As stated above, OMEC exercised its rights under the Put Option to sell the Otay Mesa plant to SDG&E which eliminates one of the concerns of ORA and TURN on whether the OMEC acquisition would occur. We find TURN's concern about the uncertainty of the acquisition price to be of little merit as a valuation of \$280.0 million for the Otay Mesa plant was already approved in D.06-09-021²⁰⁷ and we find that any adjustments to the set price based on the results of SDG&E's due diligence would be minor relative to the acquisition price. In

²⁰⁶ Resolution E-4981 at 10 to 11.

²⁰⁷ Exhibit 100 at DB/GS-15.

addition, the set price is significantly below the net book value of Palomar,²⁰⁸ a comparable plant to Otay Mesa, so there is little danger of ratepayers paying more than the value of the asset.

However, we find that Resolution E-4981 which approved SDG&E's request in Advice Letter 3294-E for a proposed Confirmation between SDG&E and OMEC for local, system and flexible capacity from the Otay Mesa plant between October 3, 2019 through August 31, 2024 makes the acquisition of the Otay Mesa plant highly uncertain. We find this to be true despite the exercise by OMEC of the Put Option to sell Otay Mesa to SDG&E and despite the fact that D.19-08-014 denied POC's application for rehearing of Resolution E-4981. Even though the Put Option was exercised, sale of Otay Mesa will not become final until October 3, 2019 or after the PPTA expires. Furthermore, the Confirmation will not be final and unappealable until the time expires for POC to seek a Court challenge to D.19-08-014 or a Court rejects any POC challenge. Therefore, we find it prudent to consider the potential impact of Resolution E-4981 in our analysis of the costs being included for the acquisition of Otay Mesa.

Removing OMEC costs results in the following totals to SDG&E's O&M and capital forecasts:

O&M and Capital	2017	2018	2019
O&M with OMEC	n/a	n/a	\$63,411,000
O&M without OMEC	n/a	n/a	\$40,615,000
Capital with OMEC	\$13,314,000	\$292,826,000	\$17,371,000
Capital without OMEC	\$13,314,000	\$12,826,000	\$12,020,000

²⁰⁸ Exhibit 97 at DSB-5.

In its Comment to the Proposed Decision, SDG&E provided updated information that OMEC agreed to rescind its exercise of and waive any further right to the put option that the Commission approved in D.06-09-021, and which OMEC had exercised on March 28, 2019. SDG&E states that it sent Notification of Status of Capacity Agreement in R.17-09-020 and to the service list of this proceeding on August 23, 2019, explaining that OMEC is rescinding its exercise of the put option and that SDG&E will proceed in accordance with the terms set forth in its Commission-approved 59-month Confirmation, as amended, and will not purchase the OMEC facility.

In light of the recent developments described above, we find it reasonable for OMEC-related costs to be removed from the GRC. We also find no need to authorize establishment of the OMABA. The following OMEC costs should be removed from SDG&E's forecasts for Electric Generation: \$22.796 million in non-shared O&M costs and capital costs of \$280.0 million in 2018 and \$5.351 million in 2019. TURN and ORA proposed reductions of \$0.493 million and \$1.1 million for Otay Mesa O&M costs but these become moot since we are disallowing the proposed OMEC costs.

20.5.2. O&M Costs

Consistent with other sections of this decision, we find that select use or updates using 2017 data may lead to inconsistency since not all data will be updated. We recognize that there are instances where this is necessary, reasonable, and prudent but this is not the case here and especially because no reason was provided on why it is appropriate to include 2017 data other than the fact that 2017 costs are lower than the five-year historical average from 2012 to 2016. Thus, we find SDG&E's use of a five-year average to be more appropriate and reasonable. In its Reply Brief, SDG&E agreed to removed the small cost of

\$5,000 for chamber of commerce dues in Boulder City that TURN objects to.²⁰⁹ SDG&E agrees with TURN's position regarding \$0.119 million in crane costs that should be removed from costs for Palomar because these costs are not expected to recur due to the installation of a steam turbine gantry crane in Palomar. This reduces the TY2019 costs for Palomar to \$18.437 million. Based on the above, we find that the Generation Plant TY2019 forecasts of \$18.437 million for Palomar, \$15.561 million for Desert Star, \$2.380 million for Miramar, and \$1.078 million for Cuyamaca are reasonable and should be approved. Costs for these four generation plants are relatively close to 2016 costs.

For Administration, the difference between TURN's recommendation and SDG&E's proposal is the inclusion of two FTEs that are part of 2016 costs. One of those positions remained vacant in 2017 and part of 2018 resulting in a lower three-year average as compared to just base year costs. However, we find that there is no indication from the evidence presented that the position that became vacant in 2017 was meant to be vacant and that the job functions to be performed by the position continued to exist. Thus, we find that base year costs are better reflective of TY2019 costs and that SDG&E's forecast for Administration of \$0.469 million is reasonable and should be authorized.

Parties do not object to the forecast for SONGS and we find that the reasonableness of the costs are to be addressed in SCE's TY2018 GRC. SCE then merely bills SDG&E 20 percent of the costs determined in SCE's GRC representing SDG&E's 20 percent ownership cost for SONGS-related expenses.

²⁰⁹ SoCalGas and SDG&E Reply Brief at 133.

With regards to the forecast for Resource Planning, SDG&E states that incremental costs were added to the TY2019 forecast to reflect staffing needs to meet GHG target and reliability needs as well as an additional FTE for a Resource Planning Manager to address additional activities as the Commission moves to an Integrated Resource Planning process as required by SB 350. However, we agree with TURN that meeting GHG target needs should not be considered as incremental work given that this has been a relatively longstanding activity that is being performed by SDG&E. We also agree with TURN that the testimony submitted by SDG&E concerning the additional FTE for the Resource Planning Manager position only states that the position is being added but does not clearly establish the work to be performed and that the work is incremental in nature. Thus, we find TURN's recommended forecast of \$0.815 million for Resource Planning is more reasonable and should be approved.

To summarize, SDG&E's TY2019 forecast \$63.411 million for O&M costs should be authorized except subject to reductions of \$22.915 million for Generation Plant and \$0.280 million for Resource Planning. SDG&E should also remove \$5,000 for the chamber of Commerce dues in 2016 for Boulder City.

20.5.3. Capital Costs

For this rate case, we agree with SDG&E's proposal to use a general capital budget rather than specific capital projects to allow flexibility and adaptability to meet current and future plant needs. SDG&E will instead plan, schedule, and perform specific capital projects as appropriate. We agree with the method proposed above. We also find that basing projected costs on the five-year historical is appropriate and reasonable. We disagree with ORA's proposal to use 2017 recorded costs consistent with our view in this decision concerning

updating only select data to 2017 actuals. Thus, for capital costs, we find that SDG&E's forecasts of \$13.314 million for 2017, \$12.826 million in 2018, and \$12.020 million for 2019 should be authorized. TURN and SDG&E agree with TURN's finding concerning two projects concerning Palomar that should have been disallowed in 2012 and were still included in the revenue requirement beginning in 2016.²¹⁰ We agree with SDG&E's proposal to remove these costs retroactive to 2016 with overcollections returned to ratepayers.²¹¹ These costs have already been removed from the TY2019 forecasts in SDG&E's update testimony.²¹²

21. Electric Distribution

SDG&E operates and maintains an electric distribution system that serves approximately 3.1 million people through approximately 1.4 million meters. Its service territory spans more than 4,100 square miles. The system includes 134 distribution substations, 1,035 distribution circuits, 225,697 poles, 10,558 miles of underground systems, 6,527 miles of overhead systems, and various other components of distribution equipment.²¹³ SDG&E's customer mix is approximately 1.27 million residential customers, 158,000 commercial and industrial customers, and 46,000 street light customers. In addition, there are approximately 450,000 trees that are in close proximity of overhead lines that are managed through SDG&E's vegetation management program. Around 62 percent of the distribution system is comprised of underground facilities.

²¹⁰ Exhibit 494 at 65 to 66.

²¹¹ Advice Letter 3317-E

²¹² Exhibit 514 Attachment I at I-1.

²¹³ Exhibit 68 at WHS-1.

21.1. O&M Costs

SDG&E's TY2019 forecast for O&M costs is \$168.626 million²¹⁴ which is \$46.159 million higher than 2016 adjusted, recorded expenses. The O&M section is comprised of 26 different cost categories. The TY2019 forecast incorporates \$8.483 million in O&M savings from FOF.

21.1.1. RAMP

Part of the requested costs is driven by risk mitigation activities pursuant to the RAMP process. The table below summarizes key risks being mitigated and the estimated O&M costs for the mitigation activities that are planned to be undertaken. These costs are embedded in the O&M costs being requested and the reasonableness of these costs are reviewed in the O&M sections that they appear in.

RAMP Risk	Embedded 2016 Base Costs	TY2019 Incremental Costs	Total Costs
Wildfires Caused by SDG&E Equipment	\$34,919,000	\$5,807,000	\$40,726,000
Employee, Contractor, and Public Safety	\$29,610,000	\$6,000,000	\$35,610,000
Distributed Energy Resources	\$0	\$575,000	\$575,000
Aviation Incident	\$55,000	\$355,000	\$410,000
Unmanned Aircraft System Incident	\$0	\$162,000	\$162,000
Electric Infrastructure Integrity	\$1,261,000	\$21,040,000	\$22,301,000
Records Management	\$4,855,000	\$1,281,000	\$6,136,000
Climate Change Adaptation	\$24,000	\$403,000	\$427,000
Workforce Planning	\$1,206,000	\$152,000	\$1,358,000
RAMP-related O&M total	\$71,930,000	\$35,775,000	\$107,705,000

²¹⁴ Revised from \$168.626 million to \$168.185 million in the Update Testimony (Exhibit 514) at Attachment I.

Most of the RAMP activities were already being performed but new and enhanced safety-related activities to mitigate risk have been included as a result of the RAMP process. O&M costs for incremental activities comprise \$35.775 million out of the \$46.159 million increase in O&M costs from 2016 and total RAMP-related costs of \$107.705 million comprise a large portion of the \$168.626 million in total O&M costs being requested for TY2019. The discussion below will focus on the incremental requests for TY2019.

Wildfire Caused by SDG&E Equipment

SDG&E utilizes a helitanker asset for three months but seeks to increase usage year-round because the fire season has become a year-round risk. In addition, SDG&E seeks additional funds for its Long Span program which is designed to reduce the risk of wildfires through the inspection and repair of long distribution spans which have greater risk especially during high wind events. Finally, incremental funds are also requested for the Weather Station program which provides real-time wind and weather information in order to help understand local wind conditions.

Employee, Contractor, Customer, and Public Safety

The incremental request is for the Customer Safety Communications program which is designed to reduce risk of a public safety incident through further education on electrical and gas hazards.

Distributed Energy Resources (DERs)

The incremental request for DERs is for risk mitigation efforts relating to improved software tools designed to further reduce risk associated with DER by enhancing SDG&E's ability to forecast DER load and growth.

Aviation Incident

Incremental efforts include increased oversight of contractors, pilot currency and proficiency training, and aviation construction and observation enhancements.

Unmanned Aircraft System (UAS) Incident

Incremental activities include development of a UAS training program to further reduce UAS incidents.

Electric Infrastructure Integrity

A large portion of the incremental requests are under mitigation which includes enhancements to the Pole Risk Management and Engineering (PRiME) program which seeks to reduce risks by evaluating thousands of wood poles throughout SDG&E's service territory to ensure that they continue to meet structural integrity requirements.

Records Management

Incremental costs are to improve controls around compliance with records management policies and procedures.

Climate Change Adaptation

SDG&E will partner with universities to investigate the latest science to inform system planning decisions related to climate change.

Workforce Planning

Incremental activities include formal training programs for engineering.

21.1.2. Non-Shared O&M

The table below summarizes the TY2019 forecasts for the 26 O&M cost categories.²¹⁵

²¹⁵ SDG&E's TY2019 forecasts include revisions from its Update Testimony (Exhibit 514), Attachment I.

Non-shared O&M	2019	Change from 2016
Reliability & Capacity	\$341,000	\$97,000
Construction Services	\$18,936,000	\$13,573,000
DistOps Enterprise Geographic Info System Standards	\$1,253,000	-\$126,000
Electric Distribution Operations	\$22,546,000	\$6,956,000
Kearny Operations Services	\$2,133,000	\$784,000
Grid Operations	\$567,000	-\$100,000
Officer	\$772,000	\$0
Project Management	\$1,347,000	\$687,000
Electric Regional Operations	\$46,639,000	\$11,026,000
Skills & Compliance Training	\$4,661,000	\$528,000
Service Order Team	\$161,000	\$0
Substation Construction and Operations	\$5,284,000	\$702,000
System Protection	\$1,861,000	\$401,000
Distribution and Engineering	\$4,176,000	\$1,834,000
Asset Management	\$4,610,000	\$4,610,000
Troubleshooting	\$7,796,000	-\$100,000
Vegetation Management (Pole Brushing)	\$3,741,000	\$291,000
Vegetation Management (Tree Trimming)	\$22,674,000	-\$331,000
Regional Public Affairs	\$1,802,000	-\$163,000
Major Projects	\$110,000	-\$9,000
Technology Utilization	\$1,225,000	\$183,000
Compliance Management	\$2,856,000	\$162,000
Technology Solutions and Reliability	\$3,260,000	\$716,000
Emergency Management	\$5,344,000	\$2,841,000
Strategic Planning and Business Optimization	\$2,390,000	\$760,000
DER	\$1,699,000	\$395,000
Total	\$168,184,000	\$45,717,000

21.1.2.1. Reliability & Capacity

The Reliability & Capacity group performs planning activities related to providing administrative and technical support. Typical activities include forecasting, designing, and responding to utilization of the distribution system. A three-year average was utilized to develop the forecast because the structure of

the organization changed in 2014 as certain personnel costs have been moved to Electric Regional Operations.²¹⁶ RAMP activities included in the forecast are for improved modeling tools.

We reviewed the forecast for Reliability & Capacity and find it to be reasonable. Parties do not oppose SDG&E's forecast.

21.1.2.2. Construction Services

Construction Services is responsible for installing and removing transformers and managing construction projects and field activities associated with SDG&E's electric distribution system that are performed by contractors. SDG&E utilized its base year expenses and added costs for proposed projects and activities for the TY.

ORA also proposes using SDG&E's base year recorded costs but recommends reduced funding for the incremental projects being proposed. ORA's total recommended amount is \$8.133 million. ORA adds that for TY2016, \$16.00 million was authorized for Construction Services but only \$5.363 million was spent.

FEA recommends using the two-year average from 2016 and 2017 which is \$5.659 million.

We reviewed the arguments raised by parties and reviewed the evidence presented and find that ORA's and FEA's proposed amounts do not consider the proposed projects for the TY, many of which are pursuant to mitigating risks identified in the RAMP Report. SDG&E provides a list and description of

²¹⁶ Exhibit 68 at WHS-20.

proposed projects for the TY in Exhibit 68.²¹⁷ A large part of the incremental funding is for PRiME program which is for the redesign, construction, and maintenance of overhead electric facilities including wood poles that have been subjected to increased loads due to additional attachments.

SDG&E also explains that a large part of the authorized funding for Construction Services in 2016 was re-allocated to capital-intensive activities relating to the Fire Risk Management (FiRM) program.²¹⁸ Large-scale O&M surveys of lines and structures were originally planned for 2016 but the funds were instead used for replacing conductors with known failure rates.

Regarding the fact that PRiME costs also appear in Distribution and Engineering, SDG&E explains that proposed costs here are for the construction component whereas funding requested under Distribution and Engineering are for an engineering and analysis component. With respect to Switch Replacement projects, an inspection component was included under Electric Regional Operations while the construction component for switches that fail the inspection are included here. However, we find that the amount for failed inspections is difficult to predict without conducting the inspections first and SDG&E did not provide sufficient explanation for its proposed costs for this activity. Thus, we find it reasonable to deny the requested funding of \$2.261 million for switch replacement projects at this time without prejudice to this being requested again in SDG&E's next GRC but with more information regarding the estimated funding required. Therefore, SDG&E's requested amount of \$18.936 million

²¹⁷ Exhibit 68 at WHS-23 to 28.

²¹⁸ *Id.* at WHS-11.

should be reduced by \$2.261 million resulting in \$16.675 million that should be approved.²¹⁹

21.1.2.3. Distribution Operations Enterprise GIS

The Enterprise GIS Services creates and maintains all electric distribution, transmission, telecommunications, and substation data. Costs were forecast using base year recorded data less incremental deductions due to efficiency savings.

We reviewed the forecast for Reliability & Capacity and find it to be reasonable. The data from the Enterprise GIS system is essential for maintaining safety and reliability of SDG&E's systems. Parties do not oppose SDG&E's forecast.

21.1.2.4. Electric Distribution Operations

Electric Distribution Operations Control Center is responsible for the safe, efficient, and reliable delivery of power to SDG&E's customers. The Control Center employees have overall operational control for the electric distribution system for both planned and unplanned work. According to SDG&E, system growth and grid modernization have contributed to increased workloads and so a three-year linear trend was utilized to develop the forecast as costs are expected to continue increasing. Incremental costs were added for SCADA system support and maintenance. SCADA switches allow for automated remote sectionalizing which helps in limiting the number of customers that experience outages and reducing overall outage duration.

²¹⁹ Requested amount revised from \$19.167 million to \$18.936 million in the Update Testimony (Exhibit 514) at Attachment I.

ORA and FEA oppose SDG&E's three-year linear trend forecast especially for non-labor costs and recommend reduced funding levels. ORA adds that certain incremental activities appear to be routine in nature such as maintenance costs and training costs.

We reviewed the arguments raised by the three parties and find that SDG&E did not provide sufficient testimony to justify use of a three-year linear trend. SDG&E's 2017 recorded costs are slightly lower than 2016 recorded costs which does not support SDG&E's three-year linear trend methodology. In addition, SDG&E described certain activities to support its forecast which include activities that are more routine in nature involving equipment and systems that are already in service. We recognize however, that costs have an upward trend because of anticipated increases in other O&M and capital programs which in turn results in increased costs for hardware, software, and exempt materials. Overall, we find use of a four-year linear trend for non-labor costs that includes 2017 recorded costs to be more reflective of projected costs for TY2019. A four-year trend plus incremental costs results in \$16.1 million²²⁰ for non-labor costs plus \$3.306 million of labor costs, for a total of \$19.406 million that should be approved.

21.1.2.5. Kearny Operations Services

The Kearny Operations Services has four functional groups: (a) Tool Repair is responsible for tool support needs of other workgroups; (b) Apparatus Group is responsible for salvaging line equipment removed from service; (c) Transformer Repair & High Voltage Testing is responsible for the high

²²⁰ Exhibit 71 at WHS-19.

voltage test station lab that tests and confirms the electrical condition of transformers, regulators, and other live line tools and equipment; and (d) Protective Equipment Testing Lab which tests and inspects rubber goods for electrical worker protection. Costs were forecast using a five-year average plus incremental costs for training to address workforce development.

ORA objects to the \$0.412 million in incremental funding for training and argues that these activities are already included in rates.

Recorded costs for 2012 to 2016 were \$1.978 million, \$1.959 million, \$1.603 million, \$1.717 million, and \$1.349 million respectively. Although there was a slight increase from 2014 to 2015, we find that costs have generally been decreasing. We find that a three-year average or \$1.556 million is more reflective of current costs. However, we do not object to the incremental funding of \$0.412 million to fund additional staff for additional training activities. SDG&E explained that the training activities are new activities and are thus not embedded in existing activities. The additional training will address a RAMP risk identified in the RAMP Report.²²¹ Thus, for Kearny Operations Services, we find that \$1.968 million should be authorized which reflects the three-year average plus the incremental costs being requested.

21.1.2.6. Grid Operations

Grid Operations is comprised of: (a) Energy Management Systems Operations which is responsible overall installation, testing, calibration, and maintenance for all SCADA equipment that interfaces with the Energy Management and Distribution Management systems, and (b) Mission Control

²²¹ Exhibit 68 at WHS-35.

Training System which is the facility that houses several system monitoring and control functions. Costs were forecast using the base year plus incremental additions.

We reviewed the forecast for Grid Operations and find it to be reasonable. Certain non-recurring costs associated with training during 2016 were removed which accounts for the TY forecast being less than base year recorded costs. Parties do not oppose SDG&E's forecast.

21.1.2.7. Officer

This cost category supports the costs for officers and administrative assistants in support of electric distribution. Costs also include consulting fees, benchmarking studies, office supplies, and travel expenses. Costs were forecast using the base year method as costs are expected to remain at base year levels.

We reviewed the forecast for Officer and find it to be reasonable. Costs are not projected to increase from base year levels. Parties do not oppose SDG&E's forecast.

21.1.2.8. Project Management

Project Management performs varied tasks relating to the preparation of construction orders. This includes design and engineering necessary to develop comprehensive construction orders. The construction orders represent capital work but many capital projects include small O&M components.²²² Costs were forecast using a base year method plus incremental additions.

²²² Exhibit 68 at WHS-38.

ORA and SDCAN recommend lower amounts as the forecast amount for the TY is more than double recorded costs in 2016. ORA recommends using a five-year average plus reduced incremental funding.

SDG&E utilized a base year amount of \$0.660 million because of an increased FTE count in 2016 which we find reasonable. For the incremental addition of \$0.687 million, SDG&E explains that due to retirements, training is needed to replenish the workforce through hiring and development programs. While we agree with the training programs to develop skilled workers to replace the skilled workers that leave, we agree with ORA that the funding for the employees that left should still be accounted for in rates. When an employee retires, only the employee disappears but the funding for the position remains if that position is to be retained. From the testimony presented, we find that additional personnel are not needed at this time. Thus, we find it reasonable to remove \$0.088 million from the incremental funding representing funding for additional personnel. This results in a total of \$1.259 million for Project Management that should be approved. The incremental costs being approved represent training costs and increased contractor costs because of the lack of skilled employees due to retirements.

SDCAN also recommends a bill credit or direct payment to developers when SDG&E fails to re-schedule an appointment 24 hours in advance and to pay customers and developers when installation of gas or electric lines exceeds five days. SDG&E explains that inspection requests received in the afternoon are scheduled for the next day and that the inspection routes and schedules can vary depending on the volume of work for that day and the complexity of the work. This is the same case for installation as some installations are more complex than others. Installations are also affected by a developer's completion schedule

which can be delayed. Thus, we find it reasonable to deny SDCAN's request at this time based on the evidence that was available during this GRC although SDCAN can raise this issue again in SDG&E's next GRC and present more substantial evidence.

21.1.2.9. Electric Regional Operations

Electrical Regional Operations is responsible for inspection and maintenance of SDG&E's distribution system. Electrical Regional Operations is also responsible for restoring service after outages, repairing service problems and handling customer issues, and constructing new electric infrastructure. Costs were forecast using the base year method plus additions for proposed activities.

ORA and FEA recommend using five and four-year averages respectively but the variance in recorded costs from 2012 to 2016 is not very high with costs ranging from \$32.267 million to \$35.861 million. In addition, changes in staffing levels occurred in 2016 which makes the base year costs more reflective of costs moving forward. This is supported by the fact that recorded costs in 2017 are around the same level as in 2016.

ORA also raises objections against several of SDG&E's proposed additional activities which we discuss below.

For the switch replacement projects, as discussed in the Construction Services section, the programs here focus on inspection while the focus of the switch replacement projects proposed under Construction Services are for replacements.

Regarding the Long Span inspection and repair projects, ORA argues that these have been conducted before and should already be in rates. SDG&E explains that there were no long span inspection and repair costs embedded in

2016 from which the TY2019 is based. In addition, given the importance of the proposed project for mitigating safety and wildfire risk, we find that funding for the proposed project should be approved.

Regarding the incremental funding of \$0.168 million for a new permitting group, we find that the request is reasonable as regulatory compliance with federal, state, and local laws and regulations have become more complex and this new group will help streamline the required filings and provide additional oversight to the process.

With respect to the request for additional linemen, we find the request to be reasonable in light of the new projects being proposed and because the additional linemen are intended to address outage response times and reliability which are key areas that SDG&E should seek to improve.

Finally, with regards to the Customer Communications Safety Program, we find that the program is distinct from other safety programs that SDG&E already conducts. This program will address RAMP risks identified in the RAMP Report and aims to reduce safety risk levels.

Based on the discussions regarding this section, we find that SDG&E's forecast for Electric Regional Operations is reasonable and should be authorized.

21.1.2.10. Skills and Compliance Training

This organization is responsible for the development and training of the electric distribution workforce. This includes development and training of electric linemen as well as annual training required by federal, state, and local safety laws and regulations. Training on protective equipment and commercial driver training is also included as well as safety training on the proper operation of various equipment, machinery, and vehicles. Costs were forecast using the base year method plus incremental additions for new or expanded programs.

We reviewed the forecast for Skills and Compliance Training and find it to be reasonable. Many of the included trainings are mandated by law or regulation and incremental funding addresses risk mitigation for workforce development. Parties do not object to SDG&E's forecast.

21.1.2.11. Service Order Team

The Service Order Team is responsible for planning and managing new additions and modifications primarily related to services, to the electric distribution system. Costs were forecast using the base year method.

We reviewed the forecast for the Service Order Team and find it to be reasonable. Costs are not projected to increase from base year levels. Parties do not oppose SDG&E's forecast.

21.1.2.12. Substation Construction and Operations

Substation Construction and Operations is responsible for the installation, inspection, and maintenance of approximately 134 distribution substations. Costs were forecast using a five-year average.

ORA proposes using a base year method for labor costs. SDG&E states that a five-year average is more appropriate because costs have been fluctuating. However, costs have been declining each year from 2012 to 2016. Recorded costs for 2017 shows that this trend is continuing and so we find ORA's estimate to be more reflective of projected costs for TY2019. Thus, for Substation Construction and Operations, we find ORA's recommended amount of \$4.759 million should be adopted instead of SDG&E's forecast of \$5.284 million²²³.

²²³ Requested amount revised from \$5.322 million to \$5.284 million in the Update Testimony (Exhibit 514) at Attachment I.

21.1.2.13. System Protection

System Protection includes maintaining protective relays and protection systems performed by relay technicians and commissioning new systems that are installed, performing time-based maintenance, and responding to emergencies performed by SCADA technicians. System Protection personnel are on-call during non-business hours to provide fire risk mitigation and system emergency response. Costs were forecast using a five-year average.

We reviewed the forecast for the Service Order Team and find it to be reasonable. Activities performed are dependent of inspection and maintenance requirements and emergency requirements that can vary from year to year and so the five-year average used to develop the forecast is appropriate. Parties do not object to SDG&E's forecast.

21.1.2.14. Distribution and Engineering

This workgroup is responsible for all equipment pertaining to the distribution network and responsibilities include the development and maintenance of overhead and underground equipment specifications, risk analysis and mitigation, and development of construction standards and work methods that promote and ensure safety. This also includes field investigations of equipment failure. Incremental costs are proposed in the TY for certain RAMP-related activities such as training programs for engineering groups and the PRiME program. The additional funding is for increased mitigation of several key risks identified in the RAMP Report. Costs were forecast using a three-year average plus incremental additions.

ORA disagrees with the incremental costs being requested and instead recommends normalizing these costs resulting in a proposal that includes approximately 25 percent of the incremental costs that were requested by

SDG&E. We reviewed the arguments raised and evidence presented by the two parties and find that SDG&E provided sufficient testimony explaining the necessity of the incremental projects being requested such as PRiME.

However, we agree with ORA regarding its objection to the DER Outreach Program and find that SDG&E already has funding in rates for similar outreach programs that educate the public on electric safety issues and the DER Outreach Program should be incorporated into these trainings or conducted within the funding SDG&E already has for such matters. Therefore, we find that SDG&E's requested amount of \$4.176 million should be reduced by \$0.5 million which is the request for the DER Outreach Program, resulting in \$3.676 million that should be authorized.²²⁴ This conclusion is different from our finding with regards to the Customer Communications Safety Program under Electric Regional Operations where we found that the proposed program is distinct from safety programs that are already being conducted.

SBUA recommends that SDG&E encourage small business customers to engage in energy solutions and proposes that SDG&E utilize 25 percent of its forecast amount for outreach to small businesses. However, SDG&E provided testimony showing that it already engages in activities that SBUA recommends and we find that SBUA did not provide sufficient explanation and justification for its recommended spending level for outreach to small businesses and did not point to specific shortcomings or deficiencies regarding the level of outreach to small businesses that SDG&E already engages in.

²²⁴ Requested amount revised from \$4.299 million to \$4.176 million in the Update Testimony (Exhibit 514) at Attachment I.

21.1.2.15. Asset Management

Asset Management is a newly formed group that will be involved in developing and creating strategic asset management capability for SDG&E in accordance with ISO 55000²²⁵ as recommended by SED. Costs were forecast using a zero-based methodology.

We reviewed the forecast for Asset Management and find it to be reasonable and supported by the evidence. The benefits of applying ISO 55000 standards include: (a) greater optimal balance of asset cost, asset risk, and asset performance; (b) greater internal consistency; and (c) helps ensure that employees at all levels understand their role in supporting the goals of the organization.

21.1.2.16. Troubleshooting

Troubleshooting includes funding for the Operations and Engineering workgroup which is responsible for engineering and system troubleshooting to ensure safe and reliable electric service to customers. Electric troubleshooters act as first responders and have specific skills necessary to restore electric service during emergencies and unplanned interruptions. Costs were forecast using a base year method plus incremental additions.

We reviewed the forecast for Troubleshooting and find it to be reasonable and supported by the evidence. Forecast costs for TY2019 are slightly lower than base year expenditures due to savings from FOF. Parties do not object to SDG&E's forecast.

²²⁵ ISO 55000 is an international standard covering best practices of the management of assets of any kind.

21.1.2.17. Vegetation Management (Pole Brushing)

Vegetation management is composed of the Pole Brushing and Tree Trimming programs. The Pole Brushing program is responsible for clearing flammable brush and vegetation away from SDG&E's distribution poles and applying an approved herbicide to prevent energized electrical hardware from igniting a fire. In addition, SDG&E is working with CalFire on inspecting power lines in areas with high fire threat potential. Costs were forecast using a five-year average.

FEA recommends using a four-year average from 2014 to 2017 and states that costs during 2012 and 2013 were unusually high. However, FEA does not explain why recorded costs in 2012 and 2013 should be considered as outliers other than because costs for those two years are the highest and second highest since 2012. Costs decreased from 2012 to 2013 and again in 2014 but rose slightly in 2015 and again in 2016. Thus, we find that a five-year average better captures highs and lows within the five-year timeframe. Therefore, we find SDG&E's forecast reasonable and it should be approved. With regards to relying on 2017 recorded data, as stated in other parts of the decision, we find that this could lead to inconsistent results as not all data is being updated from 2016 to 2017. We do not hesitate to rely on 2017 recorded data whenever it is appropriate to do so based on specific circumstances.

21.1.2.18. Vegetation Management (Tree Trimming)

As stated above, SDG&E's vegetation management program is composed of the Pole Brushing and Tree Trimming programs. The Tree Trimming program is responsible for inspecting and pruning or removing trees to prevent them from growing or falling into overhead power lines. Costs were forecast using a

four-year average because costs in 2012 were unusually high. In addition, SDG&E is requesting that the current one-way balancing account for Tree Trimming be authorized as a two-way balancing account.

FEA recommends using a five-year average which includes 2017 recorded data which we disagree with in this instance based on the same reasoning provided above in the Pole Brushing section. Thus, we find SDG&E's requested amount of \$22.674 million for TY2019 to be reasonable and should be approved.

FEA and ORA also oppose SDG&E's request for two-way balancing account treatment of Tree Trimming costs and recommend that the one-way balancing account treatment authorized in the TY2016 GRC be continued. We reviewed SDG&E's proposal and the objections by ORA and FEA and find that SDG&E's request is reasonable. Because of enhanced wildfire risk, SDG&E may find it necessary to conduct enhanced and additional risk mitigation activities which are difficult to predict at this time. SDG&E provided activities and additional measures being considered in Exhibits 68²²⁶ and 71.²²⁷ A two-way balancing account will enable SDG&E to act more quickly in case further activities to mitigate wildfire risk become necessary and at the same time allow SDG&E to return excess funds not utilized to ratepayers. However, if SDG&E spends more than the authorized levels for tree trimming, we require SDG&E to file a Tier 3 advice letter to recover undercollections of tree trimming costs up to 35 percent and an application for recovery of undercollections when costs exceed 35 percent over the authorized level.

²²⁶ Exhibit 68 at WHS-70.

²²⁷ Exhibit 71 at WHS-67.

21.1.2.19. Regional Public Affairs

Regional Public Affairs communicates with government agencies and serves as the point of contact for communities that SDG&E serves. Regional Public Affairs also educates officials at the county and city levels about issues that can impact customers. Costs were forecast using a three-year average.

SDCAN recommends \$0.683 million and states that SDG&E did not provide more detail regarding the activities of this workgroup. SDG&E clarifies that the amount SDCAN provided was the recorded costs in 2013 for one of the three cost centers under Regional Public Affairs and that there are two more cost centers that comprise the workgroup. As shown in Exhibit 71, recorded costs in 2013 were \$1.847 million²²⁸ which is close to three times that of SDCAN's recommended amount. SDG&E also provided more detail regarding the activities conducted by Regional Public Affairs²²⁹ which we find to be sufficient. Based on the above, we find it reasonable to approve SDG&E's requested amount for Regional Public Affairs, which is slightly lower than recorded costs in 2016 due to savings from FOF.

21.1.2.20. Major Projects

Major Projects is responsible for managing distribution and substation projects. Costs were forecast using a three-year average.

We reviewed the forecast for Major Projects and find it to be reasonable. Expenses are expected to remain consistent over the next three years and

²²⁸ Exhibit 71 at WHS-63.

²²⁹ *Id.* at WHS-65 to 66.

projected costs are even slightly less than base year expenses. Parties do not oppose SDG&E's forecast.

21.1.2.21. Technology Utilization

Technology Utilization costs are for use of advanced technologies to support system stability by offsetting the intermittency of large-scale wind and solar through large scale battery storage installations. Costs were forecast using a four-year average.

We reviewed the forecast for Technology Utilization and find it to be reasonable. Large scale battery installations will improve safety and reliability of SDG&E's electric distribution system. Parties do not oppose SDG&E's forecast.

21.1.2.22. Compliance Management

The Compliance Management workgroup ensures that SDG&E is in compliance with regulations, policies, and procedures in operating and maintaining its electric distribution system. Costs were forecast using a three-year average plus adjustments.

We reviewed the forecast for Compliance Management and find it to be reasonable. Incremental adjustments were added to the base forecast to address workforce planning risk mitigation. Parties do not object to SDG&E's forecast.

21.1.2.23. Technology Solutions and Reliability

This program includes several groups that are responsible for various system analyst and business support activities for Electric Operations including hardware support for field operations, tracking and reporting on reliability indices, etc. Costs were forecast using a five-year average plus incremental additions to address workforce development and safety and reliability mitigations.

ORA states that the incremental funding requested consists of routine activities that are already included in base activities and that the request lacks supporting documentation. Based on our review, we find that the incremental funding requested is related to increased scope and additional work to be performed in the TY. The additional funding will also address mitigation of RAMP risks identified in the RAMP Report. We find SDG&E's request to be reasonable and it should be approved.

SDCAN states that SDG&E's reliability data, particularly the data relating to outages is misreported but SDG&E's testimony explains that the discrepancy is due to discrepancies with media reports which does not report all outages and because media reports sometimes aggregates the data that it reports. We find SDG&E's explanation to be satisfactory absent other evidence to the contrary.

21.1.2.24. Emergency Management

Emergency Management is comprised of three workgroups: Emergency Services; Meteorology; and Fire Coordination and Prevention. Emergency Services is responsible for risk mitigation and emergency response and provides planning and guidance for responding in anticipation of an incident, to an incident, and following an incident. The Meteorology Department provides weather information and daily reports that are used to make real-time operating decisions in order to safely manage and operate SDG&E's electric distribution system. SDG&E also has cameras throughout its service territory that provides visual awareness during emergency situations. Finally, the Fire Coordination and Prevention team consists of employees that have broad experience in various firefighting disciplines and coordinates with engineering, operations, and construction to build fire safety and fire prevention measures. Certain RAMP activities are embedded in historical costs such as the Fire Brigade Crew,

Weather Forecasting Models, Weather Awareness System, Wildfire Risk Reduction Model, Fire Potential Index, Utility Wildfire Prevention Teams, Emergency Management First Responder Outreach Program, Emergency Operations Center Training, and Meteorology Support. Specific details regarding these programs and activities are included in Exhibit 68.²³⁰ Costs were forecast using a base year method plus incremental adjustments.

ORA objects to the funding request for incremental activities and states that these activities are routine and should already be included in historical rates. ORA adds that SDG&E did not provide sufficient documentation for the incremental activities and proposes a normalized increase of approximately \$0.576 million over 2016 recorded costs. However, SDG&E's testimony and workpapers include incremental RAMP-related programs and activities as well as safety and reliability and environmental and regulatory compliance activities that are new and recurring that are not part of historical costs during 2016. In addition, SDG&E explains that it plans to replace all of its weather stations within a three-year period. Historical costs include maintenance costs for these weather stations but incremental costs include costs to replace these weather stations. ORA does not identify specific incremental activities that it opposes and instead states that these activities are routine. However, we find that SDG&E provided sufficient evidence to show that these activities are new. We also find that the testimony supports the necessity of these activities and we therefore conclude that SDG&E's requested amount for Emergency Management is reasonable and should be approved.

²³⁰ Exhibit 68 at WHS-83 to 85.

21.1.2.25. Strategic Planning and Business Optimization

This workgroup is responsible for assisting management by providing financial analysis, developing strategies to support financial stability, analyzing new technology, market trends, and product demands, and developing tools and improvement projects to meet customer and business needs. Costs were forecast using a five-year average.

ORA's proposes using base year costs of \$1.630 million, arguing that this is more reflective of costs for the TY. Costs from 2012 to 2016 ranged from \$1.507 million in 2012 to \$3.493 million in 2014. Costs increased twice and decreased twice which supports SDG&E's argument that costs have been fluctuating and a five-year average better captures increases and decreases over the five year period. Furthermore, ORA does not object to the activities included and only proposes a different forecasting method. However, we find that a five-year forecast in this case better captures increases and decreases that may occur each year and thus find that SDG&E's forecast of \$2.390 million is reasonable and should be approved.

21.1.2.26. Distributed Energy Resources

The DER workgroup uses advanced technology to lessen the impact of DER growth and integration on electric reliability, public safety, and operational flexibility. Technology used includes inverter technology, advanced controls and communications, and other intelligent electronic devices. Costs for DER were forecast using a base year method since the workgroup is still relatively new such that historical costs may not be indicative of future spending.

We reviewed the forecast for DER and find it to be reasonable. Parties do not object to SDG&E's forecast.

21.1.3. Summary

To summarize, SDG&E's O&M forecasts are approved except for the following adjustments:

Construction Services

\$16.675 million instead of the requested \$18.936 million²³¹.

Electric Distribution Operations

\$19.406 million instead of \$22.546 million.

Kearny Operations

\$1.968 million instead of \$2.133 million.

Project Management

\$1.259 million instead of \$1.347 million.

Substation Construction and Operations

\$4.759 million instead of \$5.284 million²³².

Distribution and Engineering

\$3.676 million instead of \$4.176 million²³³.

21.1.4. Performance Based Ratemaking

SDG&E proposes to discontinue the Performance Based Ratemaking (PBR) mechanism that was that was approved in D.14-09-005²³⁴ and continued in

²³¹ Requested amount revised from \$19.167 million to \$18.936 million in the Update Testimony (Exhibit 514) at Attachment I.

²³² Requested amount revised from \$5.322 million to \$5.284 million in the Update Testimony (Exhibit 514) at Attachment I.

²³³ Requested amount revised from \$4.299 million to \$4.176 million in the Update Testimony (Exhibit 514) at Attachment I.

²³⁴ D.14-09-005 was issued in response to a joint petition for modification of D.13-05-010 that SDG&E and CUE filed and set forth the electric reliability performance measures for SDG&E's 2012 GRC.

SDG&E's TY2016 GRC. The PBR mechanism provided incentives for meeting target values using four reliability indices System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Worst Circuit SAIDI, and Worst Circuit SAIFI. SDG&E states that the PBR mechanism is outdated and not necessary. CUE opposes SDG&E's request.

We reviewed the proposal and arguments raised by both CUE and SDG&E. Other parties did not comment or do not oppose SDG&E's proposal. First, we note that a PBR mechanism for electric reliability is not a requirement to the GRC application either from Commission rules or the Rate Case Plan. In this case, SDG&E does not propose a PBR mechanism although the Commission can choose to adopt one if it finds that doing so will cause a utility to improve performance and thereby increase customer satisfaction or safety.

SDG&E's PBR mechanism originated from an agreement between SDG&E and CUE to establish one during the TY2012 GRC as a means to improve reliability of SDG&E's electric system by providing financial incentives for reaching target values using the four reliability indices mentioned above. SDG&E provided testimony showing comparative SAIDI and SAIFI values with that of other investor owned utilities²³⁵ and the results show that SDG&E achieves comparatively satisfactory values. In addition, the RAMP process has shown that SDG&E also needs to prioritize safety and mitigating risks (that also include electric reliability risks) identified in the RAMP Report. Thus, a PBR mechanism on electric reliability alone may have the adverse effect of encouraging SDG&E to improve this area at the expense of others. Instead,

²³⁵ Exhibit 68 at WHS-95 to 96.

SDG&E must balance its priorities and continue to maintain high levels in both safety and reliability for both gas and electric service while at the same time ensuring that rates remain affordable. Lastly, we find that SDG&E is already proposing sufficient projects and activities in this GRC that will allow it to continue to improve on its electric reliability performance.

Based on the above, we find that continuance of the PBR mechanism that was in place during the prior GRC cycle for meeting target SAIDI and SAIFI values is not necessary for this GRC cycle. SDG&E is not proposing one and other large electric utilities such as PG&E and SCE do not have one in place.

21.2. Capital

SDG&E's request for capital expenditures is \$445.116 million for 2017, \$588.317 million for 2018, and \$700.757 million for 2019.²³⁶ Electric distribution capital projects include plant investments in electric meters, distribution substations, underground cables, and replacing and reinforcing poles. These types of investments are made to distribute electricity, to improve distribution system capacity and reliability, and to transform transmission voltage to a lower voltage for distribution. Electric Distribution capital projects are intended to maintain the delivery of safe and reliable service to SDG&E's customers.

21.2.1. IT Capital Projects

SDG&E is requesting the following for IT-related capital projects: \$36.811 million for 2017; \$38.134 million for 2018; and \$33.071 million for 2019.

²³⁶ Requested amounts revised from \$589.811 million to \$588.317 million for 2018, and from \$702.749 million to \$700.757 million for 2019 in the Update Testimony (Exhibit 514) at Attachment I.

These IT capital projects will be addressed separately from the rest of the Electric Distribution capital projects.

21.2.2. RAMP

SDG&E identified risk-mitigation projects to prioritize key safety risks in the RAMP Report. Specific risks that are being mitigated under Electric Distribution capital are listed below, including the projected costs of proposed projects to mitigate each risk.

RAMP Risk	2017	2018	2019
Wildfires Caused by SDG&E Equipment	\$90,648,000	\$115,920,000	\$148,608,000
Employee, Contractor, and Public Safety	\$6,672,000	\$8,192,000	\$10,169,000
Distributed Energy Resources	\$507,000	\$459,000	\$0
Aviation Incident	\$10,000,000	\$0	\$0
Electric Infrastructure Integrity	\$72,739,000	\$144,507,000	\$182,661,000
Total	\$180,556,000	\$269,078,000	\$341,438,000

RAMP-related capital projects are included in SDG&E's proposed capital projects for the different cost categories under Electric Distribution. As was the case in previous sections of the decision, the RAMP projects are reviewed together with other capital projects under each cost category that they appear in.

21.2.3. Primary Cost Categories

The electric distribution capital costs are divided into 11 primary cost categories and the table below provides a breakdown of the requested capital costs for each of these primary sections.

Capital	2017	2018	2019
Capacity/Expansion	\$13,269,000	\$11,002,000	\$25,176,000
Equipment/Tools/Miscellaneous ²³⁷	\$4,833,000	\$1,037,000	\$1,037,000

²³⁷ Requested amounts for Equipment/Tools/Miscellaneous revised from \$2,531,000 to \$1,037,000 for 2018, and from \$3,029,000 to \$1,037,000 for 2019 in the Update Testimony

Footnote continued on next page

Franchise	\$34,463,000	\$40,180,000	\$35,190,000
Mandated	\$33,169,000	\$34,377,000	\$32,662,000
New Business	\$55,317,000	\$57,186,000	\$60,592,000
Materials	\$24,871,000	\$26,315,000	\$27,694,000
Overhead Pools	\$85,103,000	\$120,386,000	\$162,491,000
Reliability/Improvements	\$74,863,000	\$108,418,000	\$103,448,000
Safety and Risk Management	\$83,747,000	\$113,497,000	\$184,333,000
DER	\$3,298,000	\$18,343,000	\$18,016,000
Transmission/FERC Driven Projects	\$32,183,000	\$57,576,000	\$50,118,000
Total	\$445,116,000	\$589,317,000	\$700,757,000

21.2.3.1. Capacity/Expansion

Capacity/Expansion projects are projects 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 in order to safely and reliably meet all capacity needs. As detailed in Exhibit 74, there are 13 capital projects under Capacity/Expansion.

ORA recommends using 2017 recorded costs as opposed to SDG&E's 2017 forecast. For 2018 and 2019, ORA recommends using five-year averages from 2013 to 2017. FEA supports ORA's forecasts.

Regarding the use of 2017 recorded data which ORA proposes for all 11 primary cost categories under Electric Distribution capital, as reiterated or re-stated in other portions of this decision, the rate case plan requires that the GRC application use the most recent data available at the time the application is filed. In this case, the GRC application was filed in late 2017 and so the most recent data available at the time of preparing and filing the application is the base year or 2016 data.

(Exhibit 514) at Attachment I.

As the application progresses, it is often the case that newer data becomes available such as 2017 recorded data. While we agree that recorded costs for 2017 may be thought of as more accurate and more recent than 2017 forecasts that are included in the application, we find that it is not feasible to constantly update data for the entire application. It is also not practical to update all data in the GRC because of the vast amounts of data included in the application.

As such, we find that selectively updating only certain data or in this case applying 2017 recorded costs in some instances but not in others lead to inconsistent results because not all data is being updated. For example, updating select data to 2017 recorded costs in one area which results in a lower value than the 2017 forecast would be inconsistent if another update in a different area would result in a higher value than the forecast but was not applied.

We do however recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and we shall exercise our discretion in doing so in appropriate cases. But for this GRC, based on the explanation above, we will generally not apply select updating of data if the sole reason for doing so is simply to update data without any explanation why the updated data should be applied.

Thus, in this instance, we find it more reasonable to adopt SDG&E's forecast over ORA's recommendation of using 2017 recorded costs. Incidentally, recorded costs in 2017 of \$16.796 million are higher than SDG&E's 2017 forecast of \$13.269 million.

For 2018 and 2019, we find that SDG&E's methodology is more appropriate than ORA's proposal to use historical averages. This is because of the Ocean Ranch substation project planned for 2019 which is estimated at \$14.558 million. This amount is close to \$9.5 million more than any other project

included in 2017, 2018, and 2019. SDG&E reduced planned projects for 2017 and 2018 in order to account for the Ocean Ranch substation project that was planned for 2019. SDG&E's forecasts in 2017 and 2018 are around \$4 million less than historical averages while its forecast in 2019 is around \$10 million more than historical averages. The net result though of adding total forecasts for all three years is that SDG&E's forecast is only \$1.945 million greater than ORA's despite the big disparity in 2019 forecasts. Thus, we find it reasonable to adopt SDG&E's forecasts for Capacity/Expansion capital projects.

21.2.3.2. 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.

Both ORA and FEA recommend using 2017 recorded costs which we deny as explained above concerning use of 2017 recorded data without other reasons to do so other than to simply update the data utilized in the GRC. Incidentally, recorded costs in 2017 are higher than SDG&E's forecast in this case.

ORA and FEA also recommend adjusting the 2018 and 2019 forecasts to reflect the three-year average instead of a three-year linear trend that was used. SDG&E admits that it intended to use the three-year average and not the three-year linear trend and so we accept ORA's recommended amounts of \$1.037 million each for 2018 and 2019. For 2017, we find that SDG&E's forecast of \$4.833 million should be adopted. Costs in 2017 are projected to be higher because of a one-time purchase of new fire-retardant garments and safety gear to comply with OSHA requirements.

21.2.3.3. Franchise

Franchise projects cover the conversion of overhead distribution systems to underground systems, or street and highway relocations due to improvements by governmental agencies. SDG&E is required to perform these projects pursuant to franchise agreements with city and government agencies. There are seven projects under this cost category covered by different budget codes. Costs for these projects were forecast using different methodologies such as a five or three-year average or by a zero-based methodology.

ORA recommends using 2017 recorded costs which we reject based on our above explanation concerning the use of 2017 recorded costs versus SDG&E's 2017 forecast. ORA also recommends adjustments to three projects in 2018 based on removing collectibles from these projects. ORA does not object to the 2019 forecast.

Collectibles are refundable costs obtained from customers in advance of construction. According to SDG&E, its practice is to include collectibles as part of the cost of a project in order to appropriately determine the project's total cost. The collectibles however are later removed from the RO model since ratepayers do not need to pay for these costs. We find SDG&E's method to be reasonable so as to be able to reflect the total cost of a project as opposed to what it has to collect from ratepayers for a project. What we find to be of more importance is that the collectible amount is removed from the RO model as ratepayers need not pay for these amounts since SDG&E has already received these funds from customers that paid in advance of construction. ORA's proposed method is not incorrect but we find that either method will lead to the same result.

Based on the above, we find SDG&E's forecasts of \$34,463,000 for 2017, \$40,180,000 for 2018, and \$35,190,000 for 2019 are reasonable and should be approved.

21.2.3.4. Mandated

Mandated projects are projects required by the Commission and other regulatory agencies. These projects help promote public safety and employee safety. Projects include the replacement of equipment, replacement and reinforcement of wood distribution poles, distribution switch replacements or removal, and manhole repair. As detailed in Exhibit 74, there are nine projects under this category.²³⁸

ORA recommends using 2017 recorded costs which we deny based on the earlier discussion concerning the use of 2017 recorded costs versus SDG&E's 2017 forecast. ORA also recommends reducing SDG&E's forecast by 7 percent in 2018 and 3 percent in 2019.

ORA's recommended reductions for 2018 and 2019 are based on applying a five-year average of 2013 to 2017 recorded costs. However, ORA has no specific recommendations or objections to any of the proposed capital projects under Mandated and also states in its analysis that SDG&E is requesting approximately the same level of expenditures as historical expenditures.²³⁹ We find SDG&E's forecasts to be more reasonable as compared to ORA's because they are more specific to SDG&E's projected needs in 2018 and 2019. ORA does

²³⁸ Exhibit 74 at AFC-45.

²³⁹ Exhibit 431 at 35.

not provide any reason for its recommended forecast methodology and is simply making a calculation adjustment.

CUE recommends increased spending on three specific projects totaling approximately \$8.722 million. While there may be some value in accelerating the replacement of various infrastructure as proposed by CUE, we find that this need should be balanced with increased mitigation of key risks identified in the RAMP Report that SDG&E has identified as having a higher priority at this time. Therefore, we find it reasonable to deny CUE's proposals at this time.

21.2.3.5. New Business

New Business projects are the direct result of requests from customers. These requests can include 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. SDG&E's forecast is based on the construction unit forecast, which according to SDG&E is an in-depth assessment that combines data on permit activity and the most current outlook on housing and land development presented by a variety of economic forecasting entities.²⁴⁰ There are a total of 11 capital projects under New Business.

SDG&E uses construction units as a basis for its forecast. The forecast for construction units (CU) is in turn derived from the forecast of residential permits based on data from Moody's and Global Insight. SDG&E states that these

²⁴⁰ Exhibit 74 at AFC-57.

forecasts are used by many in the construction industry and are a leading indicator for this type of forecast.

On the other hand, ORA argues that the forecast of CUs has been a poor predictor of the actual number of CUs that occur and presents data showing actual CUs in 2014 to 2016 were from 54.41 percent to 64.91 percent less than the forecast CUs.²⁴¹ ORA instead presents a forecast based on historical gross meter sets and projected meter growth. Specific details of ORA's proposed method are described in Exhibit 402.²⁴² ORA's forecasts for 2018 and 2019 using this method \$46.007 million and \$46.613 million respectively. For 2017, ORA uses recorded costs for 2017.

In Exhibit 76, SDG&E provides a brief timeline of the construction process and describes that a developer first submits a development plan which leads to the permitting process. The developer then contacts SDG&E which then performs the distribution capital work. Once this is done, the developer can then construct the building and afterwards, SDG&E can place a meter in the building to measure electric consumption.²⁴³

SDG&E states that the CU forecast is closer in time to the distribution work rather than placement of meters which occurs at the end of the process. SDG&E adds that its forecast for CUs is within 7 percent of actual CUs in 2017. However, SDG&E does not present any explanation with regards to the large discrepancies between forecast and actual CUs from 2014 to 2016. Also, based on the

²⁴¹ Exhibit 402 at 33 to 34.

²⁴² *Id.* at 35 to 38.

²⁴³ Exhibit 76 at AFC-41.

construction timeline described by SDG&E, there may be factors between submissions of development plans and distribution capital work such as delays or issues with the permitting process. In other words, once development plans are submitted, it is still uncertain that distribution work will be performed. On the other hand, looking at the time for when meters are ready to be placed, although there is some time lag as SDG&E suggests, at this stage of the process, it is more certain that the distribution work actually occurred.

Thus, in this instance, we find ORA's method to be more reasonable in light of the large discrepancies between forecast and actual CUs in 2014 to 2016. In its next GRC, SDG&E should compare forecast and actual CUs in 2018 and 2019 to see if the results in 2017 will continue. For this GRC however, we find ORA's method to be more appropriate and find that its forecasts of \$46.007 million in 2018 and \$46.613 million 2019 should be adopted. For 2017, we find it reasonable in this instance to adopt the recorded costs for 2017 as ORA did not make a calculation for 2017 using its proposed method. Actual 2017 costs of \$54.082 million are also relatively close to SDG&E's 2017 forecast.

TURN raised an objection to a specific capital project but because we are applying ORA's forecasts, TURN's proposed reduction is considered subsumed within the overall reduction that has already been applied with the adoption of ORA's forecasts.

21.2.3.6. Materials

Materials projects are for the purchase of transformers, to supply new and replacement equipment, and to maintain inventory at each electric distribution

service center. There are two blanket projects²⁴⁴ under Materials which are Electric Meters and Regulators and Transformers.

ORA agrees with SDG&E's forecast for Transformers while CUE recommends an increase of \$2.740 million. We find it reasonable to deny CUE's request to accelerate the replacement rate of transformers at this time in light of the many cost increases associated with RAMP-related projects to enhance mitigation of key risks identified in the RAMP Report.

For the Meters and Regulators blanket project, ORA agrees with SDG&E that the forecast for Meters and Regulators are driven by the forecast for new business and we agree that as the number of new electric installations increase, the number of meters to serve those installations tend to increase as well.

SDG&E and ORA derived their respective forecasts for Meters and Regulators based on their respective forecasts for New Business. And because we adopted ORA's forecast methodology for New Business, it follows that the forecast for Meters and Regulators should be based on ORA's New Business forecast. Thus, we find it reasonable to adopt ORA's forecast of \$25.317 million in 2018 and \$26.316 million for 2019 which is based on reducing the forecast for Meters and Regulators by the same overall percentage change in the New Business category. For 2017, we find that this method should be applied as well instead of using 2017 recorded costs which means that for 2017, SDG&E's forecast for Meters and Regulators of \$4.156 million should be reduced by 2.2 percent resulting in a reduction of \$91,000. Adding the 2017 forecast for

²⁴⁴ Blanket project in this case means that there are numerous purchases of meters, regulators, and transformers on a regular basis throughout the year.

transformers of \$20.715 million results in \$24.780 million for 2017 that should be approved.

TURN recommended using historical averages for Meters and Regulators but as explained above, we find that costs Meters and Regulators are related to costs for New Business and so we find ORA's general approach to be more reasonable.

21.2.3.7. Overhead Pools

The Overhead Pools reflect the costs that originate from central activities, and which are allocated to different capital projects. Examples of these costs are engineering capacity studies, reliability analysis, and preliminary design work. According to SDG&E, many of these costs cannot be attributed to a single capital project and are spread to projects that are ultimately constructed and placed into service. The central activity costs are what is referred to as pooled costs.

There are four workgroups which make up Overhead Pools which are: (a) Local Engineering - Electric Distribution Pool; (b) Local Engineering - Substation Pool; (c) Department Overhead Pool; and (d) Contract Administration Pool. As described in Exhibit 74, 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. The table below shows how the total forecasts for Overhead Pools are spread to these four workgroups.

Overhead Pools	2017	2018	2019
Local Engineering - Electric Distribution Pool	\$60,788,000	\$81,200,000	\$97,618,000
Local Engineering - Substation Pool	\$13,948,000	\$25,924,000	\$48,346,000
Department Overhead Pool	\$4,495,000	\$5,870,000	\$7,157,000
Contract Administration Pool	\$5,872,000	\$7,392,000	\$9,370,000
Total	\$85,103,000	\$120,386,000	\$162,491,000

ORA disagrees with SDG&E's method for directly charging costs to capital projects. However, SDG&E applies the Overhead Pools procedure as provided in the Code of Federal Regulations²⁴⁵ and based on the evidence submitted, we find that ORA does not provide compelling reason to prohibit the use of SDG&E's proposed procedure.

TURN proposes using historical averages to calculate the forecast for Overhead Pools but we agree with SDG&E that because of an increase in construction activities, using historical values may not be reflective of projected costs for Overhead Pools.

Based on the above, we find SDG&E's forecast methodology to be reasonable. However, we agree with both ORA and CUE that the forecasts for Overhead Pools are impacted by the amount of capital activities to be conducted and so we find that SDG&E should reduce its forecast for Overhead Pools based on the amount of capital projects that are being authorized in this decision as opposed to its forecasts. For example, if 80 percent of SDG&E's capital projects requested are authorized, then the forecast for Overhead Pools should also be reduced to 80 percent of the original forecast.

In addition, we find it reasonable to apply a one-way balancing account treatment to the funding authorized for Overhead Pools to ensure that funds associated with engineering, reliability analysis, preliminary design work, etc. relating to specific capital projects that are cancelled or postponed are not reassigned to other areas. Thus, we direct SDG&E to file a Tier 1 advice letter to

²⁴⁵ Exhibit 76 at AFC-45.

establish a one-way balancing account for Overhead Pools within 60 days from the effective date of this decision.

21.2.3.8. Reliability/Improvements

These are projects to improve and maintain the reliability of SDG&E's aging electric distribution system. According to SDG&E, cable failures remain the biggest contributor to SAIDI and SAIFI primarily due to 1,639 circuit miles remaining of unjacketed cable. As set forth in Exhibit 74, SDG&E proposes 32 capital projects under Reliability/Improvements. This includes risk mitigation projects and efforts to improve reliability through the installation of additional SCADA devices and advanced technologies.

ORA recommends using 2017 recorded costs which we deny based on the earlier discussion concerning the use of 2017 recorded costs versus SDG&E's 2017 forecast. ORA also recommends basing the forecasts for 2018 and 2019 on historical costs from 2013 to 2017 resulting in reductions to SDG&E's overall forecasts for 2018 and 2019 by around 50 percent. ORA states that many of SDG&E's requests are unsubstantiated. ORA also questions the huge increases being proposed when SDG&E already has a reliable electric distribution system.

We analyzed ORA's proposal and find that historical costs may not lead to reliable estimates of SDG&E's funding needs for Reliability/Improvements projects as many of the proposed projects in this category are new or expanded activities that have no available historical reference. In fact, many of the proposed projects utilized a zero-based methodology because of this situation. ORA points out several flaws in SDG&E's forecast methodology but also does not provide compelling reason to promote its own proposal. We evaluated both methods and find SDG&E's to be more appropriate in this case as it uses

historical averages for several projects and zero-based methods for new activities such as those relating to increased risk mitigation pursuant to the RAMP process.

TURN recommends normalizing costs for the 4kV Substation Modernization to minimize costs impacts on current SDG&E customers which we find to be reasonable. We also find TURN's proposal to extend the replacement period over a longer period of time in order to balance reliability needs with the need to keep rates reasonable affordable. TURN's proposal results in reductions of \$5.156 million for 2018 and \$7.595 million for 2019 which we find reasonable and adopt.

CUE proposes increased replacement rates for the replacement of unjacketed cables and SCADA conversions and an increased budget for the 4kV Substation Elimination. CUE's proposal totals \$27.584 million on top of SDG&E's forecasts in 2019. We find CUE's proposal lacks sufficient justification and does not provide sufficient analysis concerning the necessity of the proposed increases in replacement rates.

Based on the above, we find that SDG&E's forecast for 2017 should be adopted and that its forecasts for 2018 and 2019 should be reduced by \$5.156 million and \$7.595 million respectively.

21.2.3.9. Safety and Risk Management

These are projects to address the mitigation of safety and physical security risks. There are 11 capital projects under this section as detailed in Exhibit 74.²⁴⁶

ORA recommends using 2017 recorded costs which we deny based on the earlier discussion concerning the use of 2017 recorded costs versus SDG&Es 2017

²⁴⁶ Exhibit 74 at AFC-110 to 111.

forecast. ORA also recommends reduced amounts for the RAMP-related projects under this section which make up eight of the eleven capital projects proposed. ORA contends that the rapid increase in pace for completion of RAMP-related projects makes it doubtful that SDG&E will be able to complete these projects on time. ORA adds that SDG&E did not submit sufficient evidence to fully justify these projects.

However, ORA's across the board reduction of RAMP risks is based on historical costs and trends which may not be suitable to evaluate RAMP-related costs as many of the RAMP-related projects include new elements, activities, and programs, or increased mitigation efforts resulting from the RAMP process.

In addition, the proposed capital projects include projects such as the FiRM GRC Blanket, Fire Threat Zone SCADA Upgrades, and PRiME which are aimed or have the effect of mitigating wildfire risk which has become a key safety concern in recent times.

SDG&E also states that in addition to its testimony, it has also provided ORA and other intervenors with responses to various data requests providing more detail to the proposed projects.

TURN recommends specific adjustments to the PRiME, SF6 Switch Replacement, and Electric Integrity RAMP projects.

TURN points to an overlap of 12 percent between PRiME and the Pole Replacement and Reinforcement project but SDG&E explains that the pole count for PRiME, a system-wide pole assessment program, was reduced by 15 percent to account for any overlap with other pole projects such as the Pole Replacement and Reinforcement project as the poles under this project need not be assessed as they are already targeted for replacement or reinforcement. TURN also recommends a reduction to the estimated per pole replacement costs but we find

SDG&E's estimate has reasonable basis as it is based on the pole replacement cost associated with the FiRM program.

We agree with TURN regarding the SF6 Switch Replacement project that switches that have remaining useful lives and no leaks might not need to be proactively replaced. It is also unclear from the SDG&E testimony presented what the criteria is for switch replacements regarding these types of switches. Thus, we find it reasonable to reduce SDG&E's requested amounts for this project. TURN's recommendation is to apply recorded costs in 2017 of \$3.103 million for 2018 and 2019. However, SDG&E also argues that increased tracking of switches is required by regulatory requirements from CARB and EPA and to balance this need, we find it reasonable to authorize 50 percent of SDG&E's request for 2018 and 2019 which means reductions to SDG&E's forecasts for 2018 and 2019 of \$7.044 million each year.

For the Electric Integrity RAMP project, we find that SDG&E provided sufficient testimony to support the project and deny TURN's request to reduce the requested amount by 50 percent. We also find that a one-way balancing account is not necessary at this time.

CUE recommends increased funding for SF6 Switches, Amp Tee Connectors totaling \$27.584 million but we find that the request is not supported by sufficient evidence. CUE also recommends two-way balancing account treatment for PRiME costs which we find unnecessary at this time and in order to provide SDG&E with some flexibility to re-prioritize various risk mitigation efforts to reduce wildfire risk.

Based on the above, we find that SDG&E's requested amounts for Safety and Risk Management should be reduced by \$7.044 million each for 2018 and 2019. The forecast for 2017 should be adopted.

21.2.3.10. Distributed Energy Resources

DER refers to producers of energy but also includes newer technologies, smaller installations, and advanced battery storage. With the evolution and expansion of DER, SDG&E states that the increase in DERs is primarily associated with large increases in solar photovoltaic²⁴⁷ and that its distribution grid must evolve in order continue integrating DERs to the distribution grid and to meet the needs of customers. To accomplish this, design of the distribution grid must be changed from point source one-way power flow to multi-point two-way power flows.

ORA objects to seven of the proposed capital projects while TURN has objections to two of the projects. Most of the objections were that SDG&E did not provide enough information for the project to be approved. The table below shows the requested funding for the eight DER projects to serve as reference in the discussion of ORA's and TURN's objections to specific projects.

DER Projects	2017	2018	2019
Smart Transformers	\$258,000	\$0	\$0
Advanced Energy Storage	\$0	\$5,154,000	\$10,000,000
Borrego Springs Microgrid Enhancements	\$1,769,000	\$515,000	\$0
Vanadium Flow Battery Project	\$539,000	\$0	\$0
Microgrid for Energy Resilience	\$0	\$5,894,000	\$7,916,000
Volt/Var Optimization Transformers	\$0	\$500,000	\$100,000
ITF Integrated Test Facility	\$523,000	\$1,050,000	\$0
Borrego Microgrid 3.0	\$209,000	\$5,230,000	\$0
Total	\$3,298,000	\$18,343,000	\$18,016,000

²⁴⁷ Solar Photovoltaic is technology that converts sunlight into direct current electricity by using semiconductors.

Smart Transformers

ORA recommends reducing funding for this project but does not provide any details. According to SDG&E, the project will provide funding for the installation of monitoring devices on several transformers serving customers with charging stations. The devices will provide information on the effect of electric vehicle charging on a transformer. We reviewed SDG&E's request and find it to be reasonable and thus find that its requested amount for this project should be approved.

Advanced Energy Storage (AES)

ORA recommends a 34 percent reduction to the funding requested for this project because it is a distribution deferral proposal that needs to meet the criteria established by the Commission governing distribution deferral investments. However, as explained by SDG&E, the AES project is not intended for distribution deferral purposes although it has the potential to support distribution deferral. As described in SDG&E's testimony, the main purpose of the AES project is to help minimize impacts of intermittency and operational problems associated with the variable output of renewable energy resources. SDG&E plans to conduct strategic deployment of energy storage devices on distribution circuits with an abundance of solar photovoltaic penetration. The energy storage devices will be able to leverage excess renewable energy to charge during the day when the circuit is experiencing lighter load levels, and discharge during times of higher loading. The project will ultimately allow enabling more DERs to interconnect with SDG&E's distribution system without reaching system limitations by mitigating power backflow from distributed generators.

TURN provided testimony recommending zero funding for this project because SDG&E did not demonstrate sufficient need for the project. TURN did

not reiterate its initial objection in its opening brief. Nevertheless, we find that SDG&E complied with its burden of proof and provided sufficient justification and details concerning the project.

Therefore, we find that SDG&E's requested amounts for this project should be authorized. Additionally, we also order SDG&E to come back to the Commission in its next GRC with a report detailing the total actual project cost, including the specific cost of procuring the energy storage systems, and summarizing the specific benefits realized to ratepayers from the project.

Borrego Springs Microgrid Enhancements

ORA argues that funding for this project should be requested through the Electric Program and Investment Charge (EPIC) program. SDG&E explains that this is not an R&D project that falls under EPIC although initial phases of the Borrego Microgrid project were for R&D purposes. This project, however, will provide upgrades to the Borrego Microgrid system which is now a part of SDG&E's distribution system. Based on the above, we find the request to be reasonable and approve it.

Vanadium Flow Battery Project

ORA recommends reducing funding for this project but does not provide any details. We find the proposed project to be reasonable. The requested cost will provide funding for the installation and evaluation of a new battery system.

Microgrid for Energy Resilience

We reviewed SDG&E's testimony as well and the comments from ORA and TURN and agree that SDG&E's testimony does not provide sufficient information regarding the proposed project. The aim of the project is clear, but SDG&E's rebuttal testimony does not sufficiently address the concerns raised by ORA and TURN that the project may be duplicative what other proposed

projects will achieve and whether there are enough benefits to justify approval of the project. Based on the above, we find it reasonable to deny the project in this GRC. SDG&E can propose this project in its next GRC with more details regarding the project.

Volt/Var Optimization Transformers

ORA states that the program is based on unique equipment from a defunct manufacturer. However, SDG&E has already identified other vendors that can provide similar technology. In addition, SDG&E has 26 of the devices in inventory that it plans to install in various locations. In view of the above, we find SDG&E's requested funding for this project to be reasonable and should be approved.

Integrated Test Facility

ORA recommends reducing funding for this project but does not provide any details. The project will upgrade the Integrated Test Facility and test equipment to support safe and reliable deployment of advanced technologies. We find the request reasonable and supported by the evidence.

Borrego Microgrid 3.0

ORA objects to this project because the location is already rich with DERs and the funding request violates a spending cap imposed on another project. We find that SDG&E's rebuttal testimony sufficiently addresses the concerns raised by ORA. SDG&E explains how this project relates to and complements the Borrego Microgrid 2.0 project. SDG&E also explains that this project is distinct from another project that ORA identified and that the additional solar and storage proposed by the project is necessary to meet the long-term needs of the Borrego Springs community. We find the project to be reasonable and should be approved.

Summary for DER projects

To summarize, SDG&E's capital projects under DER are approved but the requested funding should be adjusted as follows following the above discussion on DER projects: \$3.298 million for 2017; \$12.449 million for 2018; and \$10.100 million for 2019 after deducting the amounts requested for the Microgrid for Energy Resilience project.

21.2.3.11. Transmission/FERC Driven Projects

Transmission/FERC Driven Projects cover transmission projects with a distribution component. SDG&E states that many transmission lines have underbuilt distribution facilities on them. When transmission capital work is conducted on a transmission line, related distribution facilities often need to be replaced or modified and the distribution component is funded through SDG&E's GRC. On the other hand, FERC costs are not recovered in the GRC and are covered by FERC transmission rates. As described in Exhibit 74, there are 18 projects under this category.²⁴⁸

ORA recommends using 2017 recorded costs which we reject based on our previous explanation concerning the use of 2017 recorded costs versus SDG&E's 2017 forecast. ORA also recommends adjustments to six RAMP-related projects based on a proposed methodology to allocate reasonable reductions to these RAMP-related projects. ORA also recommends \$0 funding for the Del Mar Reconfigure project stating that this project is delayed and will not likely be accomplished until 2020.

²⁴⁸ Exhibit 74 at AFC-138 to 139.

Regarding the RAMP-related projects, SDG&E explains that these projects are categorized as RAMP-related because they involve mitigation of risks identified in the RAMP report. However, the driver for these projects is to meet transmission and FERC-driven needs and the transmission component of these projects are in the process of being approved. We find SDG&E's explanation to be reasonable and that transmission component of these projects are in compliance with FERC directives, promote fire safety, and improve the reliability of SDG&E's transmission system. Thus, we find that the distribution component of these projects should also be authorized.

However, we agree with ORA's proposal regarding the Del Mar Reconfigure project as the associated permit for the project has not yet been filed as of February 2018²⁴⁹ which makes it doubtful that the project will be completed in 2019. Thus, we find it reasonable to deny SDG&E's requested amounts for this project which is \$18,000 each in 2017 and 2018 and \$2.466 million in 2019.

21.2.3.12. Summary

To summarize, SDG&E's capital forecasts for Electric Distribution are approved subject to the following adjustments:

Equipment/Tools/Miscellaneous

Forecast for 2018 and 2019 should be changed to \$1.037 million for both years.

New Business

Forecast should be changed to \$54.082 million for 2017, \$46.007 million for 2018, and \$46.613 million for 2019.

²⁴⁹ Exhibit 402 at 46.

Materials

Forecast should be changed to \$24.780 million for 2017, \$25.317 million for 2018, and \$26.316 million for 2019.

Overhead Pools

SDG&E should adjust its forecasts based on the amount of capital projects that are being authorized in this decision as opposed to its forecasts and the authorized funds should be subject to a one-way balancing account treatment.

Reliability/Improvements

Forecast should be changed to \$103.262 million for 2018 and \$95.853 million for 2019.

Safety and Risk Management

Forecast should be changed to \$106.453 million for 2018 and \$177.289 million for 2019.

Transmission/FERC Driven Projects

Forecast should be changed to \$32.165 million for 2017, \$57.558 million for 2018 and \$47.652 million for 2019.

DER Projects

Forecast should be changed to \$3.298 million for 2017, \$12.449 million for 2018, and \$10.100 million for 2019.

21.2.3.13. IT Business Unit Capital Projects

As stated previously, SDG&E is requesting \$36.811 million for 2017, \$38.134 million for 2018, and \$33.071 million for 2019 for IT-related capital

projects. These projects are briefly described in Exhibit 74²⁵⁰ with more specific details provided in the capital workpapers of SDG&E's IT witness.²⁵¹

We reviewed the 17 projects described in Exhibit 74 and find it reasonable to deny approval of the following projects: (a) Construction, Planning & Design Enhancements Phase 4; (b) Electric Geographical Information System 2018 Enhancements; (c) Engineering Project Lifecycle; and (d) Transportation and Substation Integration Phase 3. For the above-named projects, SDG&E request enhancements and improvements to existing systems without explaining why the existing systems are inadequate. For the projects that are being approved, we find these projects to be reasonable and supported by the evidence.

Two projects are not listed in Exhibit 74 but appear in the capital workpapers of the IT exhibit (Exhibit 306). These are the Distribution Interconnection Information System and the DER Management System project. We express concern that these two projects may have been obscured from parties because of the manner in which they were presented. Although we made allowances in other sections of the decision for IT Business Unit projects that only appear in workpapers and not in direct testimony, these two are especially confusing because the direct testimony for Electric Distribution list and describe the IT-related projects that are included in this section except for these two. Nevertheless, we reviewed the two projects and find it reasonable to deny approval of the DER Management System project because the workpapers do not explain why existing systems are inadequate.

²⁵⁰ Exhibit 74 at AFC-155 to 164.

²⁵¹ Exhibit 306 at 387 to 528.

Based on the above discussion, the disapproved projects result in reductions of \$6.155 million for 2017, \$15.841 million for 2018, and \$15.742 million for 2019. This results in \$30.656 million in 2017, \$22.293 million in 2018, and \$17.329 million in 2019 that should be approved for the IT capital projects in this section.

22. Customer Service

The discussion on Customer Services is divided into five subsections which follows how SoCalGas and SDG&E subdivided their testimony for Customer Services. The five subsections are: (a) Customer Services Field and Meter Reading; (b) Customer Services Operations; (c) Customer Services Information; (d) Customer Services Information and Technologies; and Customer Services Technologies Policies & Solutions.

This section also addresses the Joint Motion for Adoption of Settlement Agreement (Settlement Agreement) filed by SoCalGas, SDG&E and SBUA (Settling Parties) on March 5, 2019. The proposed Settlement Agreement between the above parties purports to resolve all outstanding issues amongst them. Most of the issues contested by SBUA concern funding and programs relating to the Customer Services section and so the proposed Settlement Agreement is discussed in this section.

22.1. Joint Settlement Motion

22.1.1. Background

SBUA's testimony concludes that SoCalGas' and SDG&E's revenue-related requests should provide greater consideration of the needs of small business within their service territories. SBUA's testimony also emphasizes that small businesses make critical contributions to the economy by adding jobs and creating new industries. SBUA makes recommendations involving revenue

requirement adjustments and program modifications that will benefit the interests and needs of small business customers and increase education and outreach to those customers because these needs are not adequately targeted and addressed by SoCalGas' and SDG&E's proposals. For example, SBUA states that unlike the individual Account Executive service afforded to large customers, not enough proactive effort has been made to provide education and outreach to small business customers on rate options, DER, and energy efficiency programs and other services that may allow small businesses to better manage and reduce their usage and rate impacts.²⁵² On the other hand, Applicants' position is that the needs of small businesses are adequately served and sufficiently addressed in the GRC funding and other requests made in the applications.

During the evidentiary from July 8, 2018 to August 8, 2018, SBUA actively participated by conducting extensive cross-examination of various witnesses, particularly, witnesses by SoCalGas and SDG&E.

After conclusion of the above hearings, Settling Parties conducted various negotiations for a possible settlement agreement. Under Rule 12.1(a) of the Rules of Practice and Procedure, parties have until 30 days from the last day of hearings within which to submit a proposed settlement agreement. According to Settling Parties, because of the complexity of litigated issues, the voluminous record of the proceedings, and the extensive discussions conducted, Settling Parties were not able to reach an agreement until around January 2019, well past the 30-day deadline after conclusion of hearings.

²⁵² Exhibit 439 at 7 to 16.

As stated in the procedural background section of the decision, Settling Parties filed a Joint Motion for Extension of Time to File Motion for Adoption of Settlement More Than 30 days After Close of Hearings. Pursuant to Rule 1.2, the Commission granted the joint motion for extension of time finding good cause to permit liberal construction and deviations from the rules in special cases where good cause is shown. In this case, the Commission agreed that these GRC proceedings are complex involving a voluminous record which resulted in Settling Parties being unable to conclude settlement negotiations within the time prescribed by the rules. In addition, the proceedings involve numerous positions raised by multiple parties and Settling Parties also had to wait until late in the proceeding for the record to be fully developed. No party objected to the request for extension and the Commission found that granting the extension does not prejudice any party and may facilitate a speedier resolution of the proceeding.

Settling parties provided notice to all parties and a settlement conference was held on January 31, 2019 during which, the Settling Parties presented the terms of their agreement. Thus, the Joint Settlement Motion complies with the rules and is ripe for consideration in this decision.

22.1.2. Terms of the Settlement Agreement

The agreements reached by the Settling Parties are particularly described in Articles 2 to 4 of the Settlement Agreement²⁵³ and summarized in the Joint Settlement Motion.²⁵⁴ The major agreements between the Settling Parties include the following:

²⁵³ Settlement Agreement at 3 to 8.

²⁵⁴ Joint Motion for Adoption for Settlement Agreement at 5 to 6.

- a. SoCalGas and SDG&E will support small businesses by conducting site visits to customer facilities, giving recommendations and referrals to energy efficiency programs, and providing energy management courses.
- b. SoCalGas and SDG&E will consult with SBUA regarding heat wave and pricing challenges, provide an informal report to address high heat events, and provide support such as offering payment arrangements for customers meeting specific criteria such as those with high bills but good payment history.
- c. Settling Parties will hold annual meetings to discuss how best to help small business customers and to determine whether additional resources are needed to meet the needs of small businesses.
- d. SoCalGas and SDG&E will expand supplier programs to non-diverse small businesses meeting specific criteria and track contractual supplier spending.
- e. SoCalGas and SDG&E will assess funding needs to help small businesses adopt DER and provide education and outreach regarding special benefits and programs related to clean transportation.

The Settling Parties provide that if the terms of the Settlement Agreement are adopted with no modifications, no revenue requirement adjustments to the GRC applications will be necessary as a result of the settlement.²⁵⁵ Settling Parties add that they agree to resolve any other issues not addressed in the Settlement Agreement amongst themselves.

22.1.3. Standard for Review

Rule 12.1(d) of the Rules of Practice Procedure provides that the Commission will only approve settlements that are reasonable in light of the record as a whole, consistent with the law, and is in the public interest.

²⁵⁵ Joint Motion for Adoption of Settlement Agreement at 7.

The Settling Parties assert that the Settlement Agreement constitutes a reasonable compromise between the Settling Parties and is in the public interest in that it allows Applicants and SBUA to assess the needs of small businesses in order to determine whether additional tools or resources are needed to better serve small business customers.

22.1.4. Discussion of Settlement Agreement

In several areas of the GRC application, SBUA makes various recommendations concerning Applicants' revenue proposals and proposed programs. For example, under Customer Services, SBUA proposes that Applicants add an additional 10 FTEs to serve the needs of small businesses. SBUA also recommends that there be at least two FTEs that are specifically trained and dedicated to address the needs of small businesses.

Settling Parties provide that if the terms of the Settlement Agreement are adopted with no modifications, no revenue requirement adjustments to the GRC applications will be necessary as a result of the settlement. This suggests that SBUA is in agreement with the program and funding proposals by Applicants but it is unclear how the various commitments being made by Applicants in the Settlement Agreement are to be funded or whether these will be funded from the amounts approved in this Decision.

Applicants make various commitments that aim to better address the needs of small businesses but the Joint Motion and the Settlement Agreement do not discuss the revenue impacts of these commitments. Again, the Settling Parties provide that the funding requests that Applicants made are sufficient to address these commitments. However, the proposed funding levels for various programs and costs centers are being litigated in these GRC proceedings and it is unclear if these commitments will be impacted if Applicants are authorized

funding levels that are less than what they have proposed. In such cases, the Settlement Agreement provides no assurance that funding for other needs will not be diverted to meet these commitments or whether shareholder funds will be used to cover any funding shortfalls.

In addition, the Settlement Agreement does little to resolve the many issues being litigated in the proceedings and even creates uncertainties as to how SBUA's recommendations in the GRC are to be resolved.

Based on the above discussion, we find that the proposed Settlement Agreement is not reasonable in light of the record as a whole. We therefore find it reasonable to deny the Joint Motion for Adoption of Settlement Agreement. The various issues raised by SBUA will be addressed in the appropriate sections of the decision and under the appropriate topics that they appear in.

22.2. Customer Services Field and Meter Reading

This section addresses SoCalGas' and SDG&E's forecast and requests relating to Customer Services Field (CS-F) and Meter Reading (CS-MR)

CS-F consists primarily of residential, commercial, and industrial field technicians who perform services at customer premises. These services include meter work, establishing and terminating gas services, lighting gas pilot lights, conducting customer appliance checks, investigating reports of potential gas leaks, investigating customer complaints of high bills, shutting off and restoring gas service for fumigations, responding to fire due to gas leaks, and other emergency incidents and related field services for customers. Field technicians work from different operating base locations that are dispersed throughout SoCalGas' and SDG&E's respective service territories.

On the other hand, CS-MR consists primarily of meter readers who complete manual meter reads at customer premises so that gas consumption can

be measured and bills generated. These services apply to customers who do not receive an AMI automated meter read. Like CS-F field technicians, meter readers are geographically dispersed across operating base locations. CS-MR only applies to SoCalGas.

22.2.1. SoCalGas

SoCalGas' TY2019 forecast for O&M costs is \$171.440 million²⁵⁶ which is \$4.239 million higher than the base year recorded expenses. For capital costs, SoCalGas is requesting \$6.838 million for 2017, \$5.040 million for 2018, and \$3.472 million for 2019.

22.2.1.1. Non-Shared O&M

The total forecast for Non-shared O&M costs is \$169.926 million²⁵⁷ which is \$3.919 million higher than 2016 adjusted, recorded expenses. The above forecast includes Non-shared O&M costs for both CS-F and CS-MR.

22.2.1.1.1. CS-F

Non-shared CS-F is comprised of four cost categories: Operations; Supervision; Dispatch; Support; and Meter Set Assembly (MSA) Inspection Program. The table below provides a summary of the TY2019 forecasts for each of these categories under CS-F.

Non-shared O&M CS-F	2019	Change from 2016
Operations	\$111,576,000	-\$859,000
Supervision	\$11,070,000	-\$330,000
Dispatch	\$8,689,000	-\$1,117,000

²⁵⁶ This total reflects adjustments from the Update Testimony. The original total for O&M costs was \$170.021 million.

²⁵⁷ This total reflects an adjustment of \$1.419 million due to an adjustment to the MSA Inspection Program as provided in the Update Testimony at 3. The original total for non-shared costs was \$168.507 million.

Support	\$17,443,000	\$1,008,000
MSA- Inspection Program	\$18,121,000 ²⁵⁸	\$12,254,000
Total	\$166,899,000	\$10,956,000

22.2.1.1.1.1. CS-F Operations

CS-F Operations consists of labor and non-labor expenses for field technicians who provide services at customer premises and includes both customer and company generated work orders. SoCalGas TY2019 funding request for CS-F Operations total \$111.576 million which is \$0.859 million less than 2016 recorded expenses. SoCalGas asserts that forecast costs are primarily driven by work order volumes which are outside their control such as customer growth, weather, the state of the economy, customer turnover, natural gas prices, customer choices, and emergency incidents. SoCalGas' utilized the 2016 order volume per active meter by order type and forecasted meter growth for 2017 to 2019 as the forecast methodology. In addition, SoCalGas is requesting incremental funding for: (a) planned meter changes (PMCs); (b) the Underset Regulator Remediation program; (c) remediation of meter transmission units (MTUs) due to annual failure rate; (d) low flow meter (LFM) and five-minute clock test; (e) field investigation for potential hot water leaks; and (f) to restore service associated with chronically inaccessible meter shut-offs.

In addition to work order of volumes and customer growth, SoCalGas states that CS-F field technician costs are influenced by the length of time it takes to travel to customer premises, the length of time it takes to complete each time of order, the amount of non-job time, training time, and vacation and sick time.

²⁵⁸ The forecast for MSA - Inspection Program was updated from \$16.702 million to \$18.121 million pursuant to Exhibit 514 (Update Testimony) at 3.

22.2.1.1.1.2. CS-F Supervision

Like CS-F field employees, CS-F supervisors are geographically dispersed across all of SoCalGas' bases. CS-F supervisors hire and coach employees, conduct safety observations, and coordinate with dispatch offices and others to address and resolve issues, respond to emergency incidents to provide on-site leadership, and manage the overall performance of CS-F employees who work from various SoCalGas bases.

A total forecast of \$11.070 million is requested by SoCalGas for TY2019 using a zero-based methodology for labor costs. SoCalGas states that a zero-based forecast is the only method that appropriately maintains the desired ratio of employees to supervisors. The average ratio for field supervisors in TY2019 is based on the 2016 average employee-to-supervisor ratio of 12:1. On the other hand, non-labor costs are based on a five-year average of historical non-labor expenses per supervisor multiplied by the forecasted number of supervisors.

22.2.1.1.1.3. CS-F Dispatch

Dispatch personnel are located at four central locations and handle daily matters that come up including: dispatching emergency orders in real time as they are received; redistributing work when one CS-F employee calls in sick or otherwise become unavailable; and redistributing work orders when CS-F employees are not able to complete all the work within the day.

SoCalGas CS-F Dispatch expense forecast for TY2019 is \$8.689 million which is lower by \$1.117 million from 2016 recorded costs. A five-year average was used to forecast costs to avoid artificially inflating or deflating results based on short-term anomalies. Cost for dispatch are primarily driven by the number of dispatchers needed to provide 24/7 and 365 day coverage to perform

dispatching functions for all 51 operating districts and all field employees, including being able to immediately dispatch all emergency orders. Unlike CS-F Operations, CS-F Dispatch costs are not driven by the order volume.

22.2.1.1.1.4. CS-F Support

SoCalGas total expense forecast for TY2019 for CS-F support is estimated at \$17.443 million compared to \$16.435 million in 2016. CS-F Support activities includes (a) centralized training; (b) field instructors who accompany new residential field technicians immediately following their formal training; (c) quality assurance (QA) inspectors and QA supervisors; (d) field technology support personnel; (e) operations clerks; (f) region and district management; and (g) administrative associates. Costs are primarily driven by the need to train new employees, maintain a technically proficient workforce, and ensure work is performed in a manner that meets SoCalGas' quality standards.

Costs were forecast based on a five-year historical average. Several management employees from the CS-F support group were temporarily re-assigned to support activities associated with the Aliso Canyon gas leak incident.

22.2.1.1.1.5. CS-F MSA Inspection Program

The MSA Inspection Program consists primarily of field technicians who perform physical, onsite inspections of each MSA to ensure ongoing and enhanced compliance with DOT-required MSA inspections for atmospheric corrosion and to identify conditions which require remediation by CS-F and distribution organizations. The DOT generally requires that each MSA be inspected every three years for atmospheric corrosion pursuant CFR §192.481.

The forecast for TY2019 is \$18.121 million²⁵⁹ compared to \$7.286 million in 2016. Costs are primarily driven by work order volumes due to the number of inspections and remediation work to be completed to meet DOT requirements. A zero-based forecast was used to develop the forecast based on volume of inspections and associated remediation work estimated to meet DOT compliance requirements and the volume of meter access issues.

22.2.1.1.2. CS-MR

CS-MR is comprised of Operations, Clerical, Supervision and Training, and Support. The table below summarizes non-shared costs for each cost category.

Non-shared O&M CS-MR	2019	Change from 2016
Operations	\$2,219,000	-\$4,813,000
Clerical	\$148,000	-\$366,000
Supervision and Training	\$355,000	-\$825,000
Support	\$305,000	-\$1,032,000
Total	\$3,027,000	-\$7,036,000

22.2.1.1.2.1. CS-MR Operations

CS-MR Operations includes part-time meter readers who are dispersed throughout SoCalGas' bases. SoCalGas is requesting \$2.219 million using a zero-based method for meter readers to capture manual reads at customer premises for customers enrolled in the AMI Opt-Out program.

Costs are primarily driven by the number of gas meters to be read each month, and to some degree, by the proficiency level of each part-time meter

²⁵⁹ This total reflects an adjustment of \$1.419 million to the MSA Inspection Program as described in Exhibit 514 (Update Testimony) at 3.

reader. The forecast is based on the average number of read orders per meter reader, training time, and vacation and sick time.

22.2.1.1.2.2. CS-MR Clerical

SoCalGas is requesting TY2019 forecast expenses of \$0.148 million for clerical personnel. CS-MR clerks handle customer information system facility updates for the new business meter process, provide general administrative support such as timekeeping, payroll and scheduling of part-time meter readers, and assistance with meter access issues. The cost driver for this cost category is the number of clerical personnel and applicable wage rates. A zero-based method was used to develop the forecast.

22.2.1.1.2.3. CS-MR Supervision and Training

The TY2019 forecast for CS-MR Supervision and Training is \$0.355 million, which is \$0.825 million lower than 2016 recorded costs. Supervisors are distributed across SoCalGas' operating bases from which meter readers work, to supervise, coach, and manage the performance of meter reading employees. Costs were forecast using a zero-based methodology.

22.2.1.1.2.4. CS-MR Support

CS-MR Support consists of a meter reading manager who supports CS-MR operations and business analysts who support the meter reading technologies including the process to download and upload to meter reading mobile data terminals or handheld devices. CS-MR Support also conducts meter reading route analysts and route realignments, project management, and other reporting and analysis activities. The primary costs driver for this cost category is the number of CS-MR support personnel and applicable wage rates. Costs are forecast at \$0.305 million using a zero-based forecast methodology.

22.2.1.1.3. Positions of Intervenors

Comments were provided by ORA, TURN, and CUE.

ORA does not oppose any of SoCalGas' O&M forecasts for CS-F and CS-MR and does not take issue with any of SoCalGas' forecasts.

TURN recommends reductions to the CS-F MSA Inspection Program based on underspending in 2017. TURN also recommends a reduction to the forecast for CS-MR Operations because costs for meter reading are expected to drop significantly following AMI deployment.

CUE proposes increased funding for CS-F Operations to enable SoCalGas to hire more employees to perform field work and for remediation of AMI modules due to failures.

22.2.1.1.4. Discussion

Parties do not disagree with SoCalGas' forecasts for CS-F Supervision, Dispatch, and Support and CS-MR Clerical, Supervision and Training, and Support. We reviewed SoCalGas' forecasts and find them to be reasonable and supported by the evidence submitted. Most of the forecasts for these cost categories are less than recorded costs for 2016 due to reduced activities, reduced costs, and some reductions from efficiencies.

CUE proposes a higher failure rate of 1.92 for AMI modules compared to 0.68 percent for SoCalGas based on the average life of an AMI module which is 20 years. CUE's proposed funding for this activity is \$5.122 million compared to \$1.814 million for SoCalGas. SoCalGas explains that there are two types of modules, one type is used by CS-F and the other type used by CS-MR which is more mechanically and electronically complex and has a higher failure rate.

SoCalGas explains how it derived the annual failure rate in Exhibit 287²⁶⁰ which is based on the annual failure rates to date, the total installed modules and the time that the modules were installed. More importantly, SoCalGas explains that the proposed 0.68 failure rate and corresponding funding of \$1.814 million only applies to the CS-F modules. The funding for CS-MR modules is included elsewhere because the AMI module failures for this type of module are handled by a different group of technicians. Thus, we find SoCalGas' forecast for this activity to be reasonable as CUE's reasoning applies both types of AMI modules whereas SoCalGas' forecast under CS-F Operations only applies to one type of AMI module.

CUE also proposes increased funding to enable the hiring of more residential energy technicians to perform adequate CS-F work. However, CUE does not specify the level of funding it proposes or the number of residential energy technicians to be added. CUE's proposal is based on the personal experience of its witness as a customer and does not provide additional evidence that customers are experiencing delays in service such as surveys or other supporting data. SoCalGas based its forecast on projected work order volumes and factored-in a 4 percent annual increase in drive times.²⁶¹ CUE also criticizes SoCalGas' "soft close" practice of leaving the gas on in premises in-between occupants but SED has already investigated this practice which has been going on for more than twenty years and found that the practice does not present

²⁶⁰ Exhibit 287 at RFG-6.

²⁶¹ Exhibit 121 at GRM-17.

unreasonable risks to customers or the public.²⁶² Based on the above, we find that CUE's proposal is vague and not supported by quantitative evidence.

To say, though, that CUE's proposal lacks evidentiary support is not to say that its proposal lacks merit. On December 28, 2017, then-Executive Director Timothy Sullivan sent a letter to Dan Skopec, Sempra Energy's Vice President for Regulatory Affairs. In that letter, Director Sullivan explained that the Commission's Consumer Affairs Branch (CAB) had heard from many SoCalGas customers angry about long delays in reconnecting service following disconnections for non-payment, and that the number of complaints dramatically exceeded those lodged against other investor owned utilities during the same time period. Director Sullivan noted, correctly, that extended cut-offs present a direct risk to health and human safety. Director Sullivan therefore urged SoCalGas to commit to restoring service to customers within 36 hours of receiving payment, which is in line with the other utilities' practices.²⁶³

We thus find that the funding level for CS-F Operations should not be below 2016 recorded costs of \$112.435 million to ensure that SoCalGas has the necessary funding to provide adequate levels of customer service. Specifically, SoCalGas should apply the additional \$0.859 million difference between 2016 recorded costs and its TY2019 forecast to its new program of restoring service to customers that have been disconnected for non-payment within 36 hours of

²⁶² *Id.* at GRM-14 referencing D.93-12-043.

²⁶³ We take official notice of Director Sullivan's letter to the extent that it recounted what CAB reported to Director Sullivan, and to the extent that Director Sullivan urged SoCalGas to comply with utility best practices. (Cal. Evid. Code, § 452, subd. (c); Cal. Code Regs., tit. 20, § 13.9.)

disconnection. This is to ensure that SoCalGas has sufficient funding for this program.

We emphasize that SoCalGas bears the burden of providing safe, reasonable, and reliable service to its customers.²⁶⁴ It bears, therefore, the burden of complying with the 36-hour reconnection mandate. Within 180 days of the date of this decision, SoCalGas shall submit a Tier 3 advice letter certifying that it is dedicating the \$0.859 million identified above to improving its reconnection rates and explaining, with specificity, what steps it is taking to ensure that reconnection times stay within that 36-hour period. SoCalGas must demonstrate that it is complying with the Executive Director's direction without underfunding or understaffing other work, such as responding to customer service requests or addressing customer safety concerns. SoCalGas must provide information about customer wait times for safety concerns and service requests and must show that those wait times are reasonable for customers requesting assistance in English as well as in other languages. SoCalGas shall serve its advice letter on the service list for this proceeding.

For CS-F MSA Inspection Program costs, TURN's recommended reduction is based primarily on underspending of approximately \$2.7 million in 2017. However, the above underspending was because SoCalGas was unable to complete all planned remediation work orders because of access issues which resulted in a backlog of approximately \$2.7 million. SoCalGas states that it intends to complete this work in addition to all other remediation work identified annually during the TY2019 GRC cycle. Both parties agree that these

²⁶⁴ Cal. Pub. Util. Code §§ 451,761.

inspection activities continue to increase and have not achieved a steady state of inspections. TURN also argues that there would still be incomplete inspections because of access issues but we find it reasonable for SoCalGas to plan on completing the inspections. Therefore, we find it reasonable to adopt SoCalGas' requested funding for CS-F MSA Inspection Program costs.

For CS-MR Operations, SoCalGas incorporates fewer meter reads into its forecast as compared to 2017 but TURN recommends further reduction of approximately 10 percent to meter reading labor costs. However, the TY2019 forecast includes costs for opt-out meter reading of approximately 160,000 opt-out meter reads while recorded costs for 2017 do not. In addition, the TY2019 forecast incorporates increased drive times which TURN did not factor into its request. Based on the above, we find SoCalGas' forecast to be more reasonable as compared to TURN's, as it takes into account opt-out meter read costs and increased drive times due to increased traffic and congestion.

22.2.1.2. Shared O&M

Shared costs are for CS-F personnel who manage and support and perform functions for both SoCalGas' and SDG&E's CS-F Operations. There are no shared services for CS-MR activities.

SoCalGas is requesting \$1.514 million in TY2019 for of shared services categorized as CS-F staff expenses. This forecast represents an increase of \$0.320 million compared to 2016 recorded expenses. SoCalGas states that these costs are needed to establish and maintain uniform policies and procedures for CS-F field personnel to follow. CS-F staff that perform shared services activities is composed primarily of management personnel who develop and implement processes, policies and procedures. SoCalGas utilized a five-year historical

average to develop its forecast to avoid potential for artificially inflating or deflating results based on short-term anomalies.

22.2.1.2.1. Discussion

TURN recommends using a four-year average from 2014 to 2017 resulting in a forecast of \$1.357 million. TURN states that costs for this category have been declining. SoCalGas argues that a four-year average is arbitrary and that TURN does not propose using a four-year average for other categories.

We disagree with SoCalGas' reasoning and find that the appropriate forecast methodology for each category should be considered as SoCalGas has done so in other instances in this GRC. In this case, costs have been declining each year from 2012 to 2016. Moreover, recorded costs in 2012 and 2013 are significantly higher relative to recorded costs in more recent years. On the other hand, the average costs from 2014 to 2016 of \$1.356 million appear to be more reflective of current costs as shown by recorded costs in 2017 which is at \$1.358 million. Based on the above, we find that a three-year average of recorded costs from 2014 to 2016 is more appropriate as the forecast methodology resulting in \$1.356 million for Shared O&M costs that should be approved.

22.2.1.3. Capital Costs

For capital costs, SoCalGas is requesting \$6.838 million for 2017, \$5.040 million for 2018, and \$3.472 million for 2019. The proposed capital projects are for information technology systems that support CS-F and CS-MR operations and meters, regulators, and tools and equipment required by CS-F Operations. The table below provides a summary of the capital costs.

Capital	2017	2018	2019
PACER OCS - Order Reprioritization Project (Phase 1)	\$440,000	\$0	\$0
MSA Inspection Project	\$328,000	\$0	\$0
SoCalGas CS-F Routing	\$1,556,000	\$0	\$0
FOF - Energy Diversion	\$788,000	\$234,000	\$0
FOF- PACER OCS - Order Reprioritization Project (Phase 2)	\$300,000	\$544,000	\$1,881,000
FOF- CS-F PACER Mobile Platform	\$3,426,000	\$4,262,000	\$1,591,000
Total	\$6,838,000	\$5,040,000	\$3,472,000

22.2.1.3.1. PACER OCS – Order Reprioritization Project (Phase 1)

CS-F uses the Portable Automated Centralized Electronic Retrieval (PACER) system to manage the work Order Completion Schedule (OCS) and field employee shift time availability. The purpose for this Phase 1 project is to improve the PACER dispatch work order scheduling and management by providing the ability to better and more granularly prioritize work based on order types, for all company generated orders.

22.2.1.3.2. MSA Inspection Project

Enhancements were made to PACER and the Customer Information Service (CIS) during 2015 to implement the new MSA Inspection Program and enable MSA Inspection Organization to perform the DOT required inspections beginning January 2016. The requested funding will be used for compliance reporting changes, creating a dedicated field employee code for the MSA inspections field workforce, and routing realignment changes.

22.2.1.3.3. SoCalGas CS-F Routing

Application and server upgrades, enhancements and replacement are required to sustain daily operations, meet regulatory compliance mandates for MSA inspections, maintain IT standard compliance, vendor support for mission critical applications, and ultimately improve route efficiency. In order to address

these issues, the CS-F routing system will undergo server and client replacement, application upgrades, and functional enhancements.

22.2.1.3.4. FOF Energy Diversion

Implementation of the proposed energy diversion program will allow SoCalGas to implement business and system processes across multiple organizations to better document, track, and manage energy diversion cases.

22.2.1.3.5. FOF PACER OCS – Order Reprioritization Project (Phase 2)

The scope of this Phase II project is to enable more granular work order management in CS-F Dispatch Offices, by order type, eliminating order categories. This phase of the project addresses prioritization of OCS orders and categories and automated scheduling of unscheduled company generated work orders.

22.2.1.3.6. FOF – CS-F PACER Mobile Platform

CS-F field employees are equipped with mobile data terminals which are being replaced with smart phones to reduce the total cost of ownership (both O&M and capital) and enable functionalities that will improve efficiency and enhance customer satisfaction, such as providing call ahead notification to customers for scheduled orders requiring entry access to customer's premises.

22.2.1.4. Summary

Based on the discussions above, we find that SoCalGas' proposed forecasts for CS-F and CS-MR should be approved except for adjustments to CS-F Operations non-shared costs and Shared O&M costs. For CS-F Operations, \$112.435 million for TY2019 should be approved instead of \$111.576 million and for Shared O&M costs, \$1.356 million should be authorized instead of \$1.514 million.

22.2.2. SDG&E

For TY2019, SDG&E requests \$23.723 million for O&M costs and \$2.250 million in 2017 for capital costs.

22.2.2.1. O&M

SDG&E's O&M costs are all non-shared. The forecast for Non-shared O&M costs for TY2019 is 23.723 million²⁶⁵ which represents an increase of \$2.284 million from base year 2016 adjusted, recorded costs. Costs are all for CS-F and includes costs for field technicians and collectors as well as costs for other supporting activities required to enable CS-F to provide services to customers. The table below summarizes SDG&E's O&M expense forecast for CS-F.

Non-shared O&M CS-F Cost Category	2019	Change from 2016
Operations	\$15,878,000 ²⁶⁶	\$2,666,000
Supervision	\$1,422,000	\$185,000
Dispatch	\$3,906,000	-\$429,000
Support	\$2,517,000	-\$138,000
Total	\$23,723,000	\$2,284,000

22.2.2.1.1. CS-F Operations

The activities performed for CS-F Operations are the same as those performed by SoCalGas CS-F Operations as described in section 22.2.1.1.1. To forecast TY2019 expenses, SDG&E utilized a three-year average from 2014 to 2016 plus incremental costs. A three-year average was chosen because 2014 to

²⁶⁵ This total reflects a reduction of \$10,000 to reflect a corresponding adjustment in the Update Testimony. The \$10,000 adjustment is also reflected under CS-F Operations.

²⁶⁶ This total reflects a reduction of \$10,000 to reflect a corresponding adjustment in the Update Testimony.

2016 represent years in which the full effects of smart meter implementation are reflected in work order volumes.

22.2.2.1.2. CS-F Supervision

The underlying activities performed by CS-F Supervision are the same as those described in the SoCalGas section for CS-F Supervision as discussed in section 22.2.1.1.1. Labor costs were forecast using a zero-based methodology while non-labor costs were based on a three-year average of historical non-labor expenses per supervisor multiplied by the forecasted number of supervisors.

22.2.2.1.3. CS-F Dispatch

The activities performed for CF-F Dispatch are the same as those described in Section 22.2.1.1.1 of the SoCalGas portion. Costs were forecast using a three-year average because SDG&E believes that this methodology better reflects the effects of smart meter implementation.

22.2.2.1.4. CS-F Support

SDG&E's forecast for CS-F Support is \$2.517 million. CS-F Support costs are for funding of activities which include: (a) centralized training; (b) field instructors; (c) QA inspectors and QA supervisors; (d) District operations managers; (e) a meter access group; (f) a safety group that fosters safer work practices; and (g) field technology support. SDG&E's forecast is based on a three-year average.

22.2.2.2. Capital

SDG&E's forecast for capital costs is \$2.250 million for 2017. Costs are for two capital projects, the Field Parts Replacement Service Program and the Service Order Routing Tool (SORT) Extension project.

22.2.2.2.1. Field Parts Replacement Service (FPRS) Program

SDG&E is requesting \$0.589 million for 2017 for costs associated with this program. The FPRS program will allow SDG&E to provide value-added services directly to customers that will add to customers' convenience and safety as well as on-the-spot repairs and reduced instances where gas services need to be shut off due to an unsafe condition.

22.2.2.2.2. SORT Extension

SDG&E uses a work order management system to issue and manage customer and company-generated work. The SORT Extension project will provide additional capabilities in scheduling, determining routes, and sending work dispatches to CS-F field technicians.

22.2.2.3. Positions of Intervenors

ORA, TURN and SDCAN provided comments to SDG&E's forecasts.

ORA and TURN recommend lower amounts for CS-F Operations and Supervision. TURN also recommends a lower amount for CS-F Support. Lastly, SDCAN proposes that certain service guarantees for missed appointments should be increased from \$50 to \$100 and that these costs be shared between ratepayers and shareholders. SDCAN also proposes that service guarantees be extended to third-party contractors for trenching.

22.2.2.4. Discussion

ORA recommends \$0.977 million less for CS-F Operations based on a different forecast method for the number of work orders under this category. TURN supports ORA's recommendation and proposes an additional reduction of \$0.147 million base on SDG&E's forecast of an additional 1 percent in drive times. SDG&E explains that it applied a three-year average for 47 out of 53 work order types and a different methodology for the 6 "irregular" order types which

account for 17 percent of the total orders that were forecasts. SoCalGas states that a different forecast methodology is more appropriate for the 6 irregular order types. For example, SDG&E states that a two-year average from 2015 to 2016 was used for First Call order types because of a change of procedure in 2014. ORA did not specifically challenge the alternate methodology used for these 6 order types and applied a three-year average for all 53 order types. Based on the above, we find SDG&E's methodology to be more appropriate as it takes into account specific circumstances regarding the 6 irregular order types for which a different forecast methodology was applied. Incidentally, these 6 order types account for 94 percent of the decrease in total work order volume from 2013 to 2017.²⁶⁷ Regarding the additional 1 percent to forecast drive times, we find the evidence presented by SoCalGas in Exhibit 124 showing increased congestion in Southern California and in San Diego to be reasonable and adequately supports the increased drive time included in the forecast. Based on all of the foregoing, we find SDG&E's forecast for CS-F Operations of \$15.878 million to be reasonable and it should be authorized.

For CS-F Supervision, because we are adopting SDG&E's forecast for CS-F Operations, we find it reasonable to approve SDG&E's forecast for CS-F Supervision. Costs for CS-F Supervision are based on the number of field technicians and employees that need to be supervised. Parties also do not object to the average employee-to-supervisor ratio of 12:1.

Regarding CS-F Support, TURN proposes using a weighted four-year average using 50 percent of 2017 recorded costs and 50 percent of the historical

²⁶⁷ Exhibit 124 at GRM-8.

average from 2014 to 2016. We agree with SDG&E that TURN's proposed method places on overly high reliance on 2017 recorded costs without sufficient justification. Thus, we reject TURN's proposal and find it reasonable to adopt SDG&E's forecast of \$2.517 million.

We reviewed the forecast for CS-F Support and find the forecast to be reasonable. Likewise, we reviewed the SDG&E's proposed capital projects and find the two projects reasonable and supported by the evidence. We agree with the forecast methodology utilized and the forecasts for these two projects which are aimed at improving on-the-spot repairs and improving scheduling and routing of field technicians. Parties do not oppose any of these forecasts.

Regarding SDCAN's request for increased credits for missed appointments, SDG&E explains that missed appointments normally occur because field personnel have to respond to gas emergency orders when safety incidents such as hissing sounds or gas smells are reported by customers. SDG&E also explains that a system upgrade resulted in a higher number of missed appointments being reported. After the error was corrected, the 2017 recorded data shows a total of 215 missed appointments out of 66,241 total appointments.²⁶⁸ We find the level of missed appointments which is at 0.3 percent to be acceptable and find no need to increase the credits awarded to customers for missed appointments. Also, the \$50 credit for missed appointments is already being paid for by shareholders.²⁶⁹ For service

²⁶⁸ Exhibit 124 at GRM-22.

²⁶⁹ *Ibid.*

guarantees involving third-party contractors, this is an Electric Distribution activity which is discussed in section 21.1.2.8 of the decision.

We reviewed the forecast for CS-F Dispatch and find it to be reasonable and supported by the evidence. Parties do not oppose SDG&E's forecast for this cost category.

Summarizing the above discussion, we find SDG&E's CS-F O&M forecast of \$23.723 million and capital forecast of \$2.250 million for 2017 to be reasonable and should be adopted.

22.2.2.5. Smart Meter Opt-Out Program

In D.12-04-019 and D.14-12-078, the Commission modified SDG&E's smart meter Program to include an analog meter option for residential customers who do not wish to have a smart meter installed (Opt-Out program).

SDG&E implemented modifications to its billing system to be able to charge opt-out fees to customers who enrolled in the Opt-Out program. Implementation costs for the Opt-Out program include field costs to manually read meters and to replace smart meters with analog meters, as well as office costs for related activities such as such as communication and purchase of additional analog devices.

22.2.2.5.1. Smart Meter Opt-Out Balancing Account (SMOBA)

D.14-12-078 authorized SDG&E to recover actual costs associated with implementing the Opt-Out program up to \$1.447 million. The decision also authorized SDG&E to transfer amounts recorded in the Smart Meter Opt-Out Memorandum Account (SMOMA) to the SMOBA. According to SDG&E, because D.14-12-078 was issued in December 2014, implementation costs for the Opt-Out program were not included in the TY2016 GRC. Thus, SDG&E is

requesting a true-up of balances recorded in the SMOBA and authority to close out the SMOBA in this GRC.

22.2.2.5.2. Discussion

As stated above, D.14-12-078 authorizing implementation of the Opt-Out program was issued in December 2014 and was not included in the TY2016 GRC which was filed in November of 2014. Thus, we find it reasonable to address a true-up of balances recorded in the SMOBA in this GRC. We find the SMOBA balances as of December 31, 2018 for electric and gas as reasonable and supported by the evidence. Parties also do not object to SDG&E's request or the SMOBA balances that have been recorded as of December 31, 2018. Therefore, we authorize SDG&E to recover these amounts and to close out the SMOBA which is no longer necessary as costs for Opt-Out program are incorporated into the GRC revenue requirement moving forward.

22.3. Customer Services Office Operations

This section addresses the forecasts and requests relating to the Customer Services Office Operations (CS-OO) for both SoCalGas and SDG&E.

22.3.1. SoCalGas

For TY2019, SoCalGas requests \$90.008 million, a decrease of \$2.414 million from 2016 adjusted, recorded expenses to support the activities within CS-OO to deliver services to Customer Contact Centers (CCC), Branch Offices and Authorized Payment Locations (APL), Billing & Payments, Credit and Collections, and other related supporting functions. For capital costs, SoCalGas is requesting \$13.190 million for 2017, \$12.412 million for 2018, and \$23.663 million for 2019.

Costs of approximately \$2.531 million are RAMP-related costs associated with mitigating risks relating to Employee, Contractor, Customer, and Public

Safety. The above estimate includes \$1.474 million in incremental RAMP expenses projected for the TY.

Costs relating to the Aliso Canyon gas leak incident of approximately \$6.294 million for TY2019 are excluded from the forecast. Costs have also been removed from historical information that was utilized by SoCalGas' witnesses.

22.3.1.1. Non-Shared O&M

The total forecast for non-shared O&M costs is \$84.516 million which is \$2.503 million lower than 2016 adjusted, recorded costs. The table below summarizes the forecast for the different cost categories and the difference from 2016 costs. All costs were forecast using a base year method as costs are forecast to remain at around base year levels. FOF savings of approximately \$9.565 million are incorporated in the O&M forecasts.

Non-shared O&M CS-OO	TY2019	Change from 2016
CCC Operations	\$29,872,000	-\$271,000
CCC Support	\$9,024,000	\$1,242,000
Branch Offices	\$12,012,000	\$420,000
Billing Services	\$6,265,000	-\$703,000
Measurement Data Operations (MDO)	\$1,043,000	-\$271,000
Credit & Collections	\$4,100,000	-\$121,000
Credit & Collections Postage	\$1,003,000 ²⁷⁰	\$8,000
Remittance Processing	\$3,994,000	-\$934,000
Remittance Processing Postage	\$14,027,000 ²⁷¹	-\$2,984,000
CS Other Office Ops & Technology	\$3,180,000	\$1,115,000
Total	\$84,516,000	-\$2,503,000

22.3.1.1.1. Customer Contact Center Operations

The CCC Operations handles a variety of customer service needs. The largest volume of interactions is for billing and payment inquiries and customer-requested service orders. CCC is also the first point of company contact for emergencies and provides a critical support role in the safety of SoCalGas' systems as well as public safety. Costs include necessary funding for answering customer calls, responding to customer e-mails, and responding to other customer account related inquiries.

22.3.1.1.2. Customer Contact Center Support

CCC Support provides necessary support services to keep CCC Operations efficient and productive such as conducting training and developing training

²⁷⁰ The total for Credit & Collections Postage was updated from \$995,000 to \$1,003,000 pursuant to the Exhibit 514 (Update Filing). The update also results in an addition to the Non-shared O&M total.

²⁷¹ The total for Remittance Processing Postage was updated from \$13.812 million to \$14.027 million pursuant to the Update Filing. The update also results in a change to the Non-shared O&M total.

materials for customer service representatives and support staff, developing procedures, conducting data and trend analysis, and other related support functions.

22.3.1.1.3. Branch Offices

SoCalGas currently has 94 full-time and 74 part-time employees located in 44 branch offices throughout its service territory, which provide customers options of paying their bills-in person, inquiring about accounts, and completing other customer service transactions. Approximately 98 percent of all branch office transactions are related to bill payments. SoCalGas also provides customer services through a network of APLs which provide payment services at convenient locations and extended hours with no transaction fee to customers.

22.3.1.1.4. Billing Services

Billing Services is responsible for calculating bills and maintaining accurate customer account information. Billing Services at SoCalGas consists of two distinct organizations are divided into: (a) Billing for residential and industrial customers (Mass Market Billing); and (b) Billing for large commercial and industrial customers (Major Market Billing).

22.3.1.1.5. Measurement Data Operations (MDO)

MDO monitors and maintains accurate and timely usage measurement reporting to support SoCalGas and SDG&E Major Market Billing functions for almost 1,300 large gas volume meters. These meters are equipped with communication devices that enable meter usage data to be collected and transmitted electronically.

22.3.1.1.6. Credit & Collections

Credit & Collections establishes and implements policies and procedures to ensure that collections activities are effectively performed. Activities include

accounts receivable management reporting and analysis, credit process review and improvement, management of outside collection agencies, skip tracing or research to locate a customer after a service termination in which the final bill reaches delinquent status, final bill collection, credit investigations, identification validations, and bankruptcy processing.

22.3.1.1.7. Credit & Collections Postage

Credit & Collections postage expenses are for costs of mailing collection notices.

22.3.1.1.8. Remittance Processing

Remittance Processing provides printing and inserting services for customer bills, notices, letters, and other customer correspondence as well as management support for payment processing activities. Expenses include the labor costs associated with these activities as well as non-labor costs for paper stock, bill forms, envelopes, stationery items, printer and inserter machine maintenance, and associated consumable supplies.

22.3.1.1.9. Remittance Processing Postage

Remittance Process Postage expenses include costs of mailing customer bills, notices, letters, and other customer correspondence. Postage for bill delivery includes postage for paper bills and notices mailed through United States Postal Service (USPS). The postage expense depends on current postage rates, which are determined by the USPS, and the volume of paper bills and notices, which are impacted by customer growth as well as electronic bill adoption levels.

**22.3.1.1.10. Customer Service Other Office
Ops & Technology**

CS Other Office Ops & Technology includes activities performed by Customer Operations Technology, Customer Service Technology Project

Management, and the VP for CS. SoCalGas is also requesting incremental costs of \$1.115 million which will be used for the Customer Energy Data Privacy Program, increased support for mobile customer applications, data analytics, and technology, and for a summer intern program.

Costs for the Energy Data Privacy Program are currently being tracked in the Energy Data Request Memorandum (EDRMA) pursuant to D.12-08-045²⁷² and SoCalGas is requesting recovery of the current balance of \$1.108 million. Subsequently, SoCalGas is requesting closure of the EDRMA as costs for the program are included in the TY2019 forecast for this group.

22.3.1.1.11. Positions of Intervenors

Comments were provided by ORA, TURN, and CUE.

ORA does not oppose SoCalGas' forecasts except for CCC Support where it recommends \$8.857 million or a reduction of \$0.167 million from SoCalGas forecast. ORA disagrees with the above adjustment for 2 FTEs for the expansion of the special investigation team. ORA states that SoCalGas did not conduct a formal cost study related to these positions and that they are able to perform these activities without the additional FTEs.

TURN recommends reductions totaling \$4.033 million to the forecasts for CCC Operations, CCC Support, Branch Offices, Billing Services, MDO, Credit and Collections Postage, Remittance Processing Postage, and CS Other Office Ops & Technology.

CUE does not propose a specific adjustment to SoCalGas' CCC forecasts but states that SoCalGas does not have a mandatory level of service and that

²⁷² D.12-08-045 OP 5.

customers are not able to reach representatives for their service requests, safety concerns, or billing questions. CUE adds that customers are also harmed because My Account is only presented in English.

22.3.1.1.12. Discussion

TURN recommends a reduction of approximately \$2.335 million for CCC Operations because of reduced call volumes being handled by CS representatives and SoCalGas' Interactive Voice Response (IVR) system based on 2017 data. This is contrary to CUE's request to add an unspecified number of CS representatives over SoCalGas' forecast in order to improve the level of service. We find that SoCalGas takes a more balanced approach by taking into account reduced call volumes but as the same time aims to improve its level of service as more calls are being transitioned into being handled by the IVR system. The TY2019 represents a reduction from base year levels but leaves enough funding to improve the current level of service. TURN's argument does not address improving the level of service while CUE's proposal does not take into account reduced call volumes.

For CCC Support, TURN recommends using a two-year average which is also based on its above argument regarding reduced call volumes. ORA does not take issue with SoCalGas' base forecast but opposes an adjustment for two FTEs or expansion of the investigation team. TURN states that ORA's proposal partly overlaps with their own recommendations. Following our discussion above about balancing reduced customer calls with improving customer service levels, we likewise find that SoCalGas' base forecast is more appropriate. However, we agree with ORA that SoCalGas did not conduct a formal study regarding the two additional FTEs for expansion of the investigation team. ORA also shows in Exhibit 412 that the number of FTEs for the special investigation

clerks have been relatively steady at close to 6.5 FTEs during last few years.²⁷³ Thus, we find it reasonable to reduce SoCalGas' forecast by ORA's recommended amount of \$0.167 million resulting in a forecast of \$8.857 million. This reduction also partially addresses TURN's concerns. CUE also had issues that My Account is presented only in English but does not substantiate the harm it is alleging. CUE also criticized the long wait times for calls handled by the IVR system but SoCalGas presented survey evidence that callers rate their hold times as reasonable.

With regards to the other proposed reductions by TURN, we find that TURN's recommendations are based on recorded 2017 costs being lower than SoCalGas' 2017 forecasts. TURN recommends using either 2017 recorded costs or a two-year average of 2016 and 2017 costs as opposed to SoCalGas' base year forecast methodology. However, as stated in other sections of the decision, updating some data to 2017 recorded costs but not doing so for others leads to inconsistencies unless there is appropriate or compelling reason to do so which we do not find in this case. TURN does not provide sufficient evidence or other reasons to show that recorded costs in 2017 are more indicative of costs and conditions for TY2019. On the other hand, SoCalGas explains that lower costs for 2017 are because of temporary factors such as the closure of branch offices for a longer than normal period and because of partial year vacancies. In addition, recorded costs for 2017 are in many instances only slightly lower than SoCalGas' 2017 forecasts and within acceptable levels given that forecasts are generally not meant to be 100 percent accurate.

²⁷³ Exhibit 412 at 14.

Based on the above, we find SoCalGas' Non-shared O&M forecasts to be reasonable and they should be approved subject to the \$0.167 million reduction to CCC Support discussed above. We reviewed the request to recover the current balance under the EDRMA of \$1.108 million and find the request reasonable and grant it, as well as the request to thereafter discontinue this memorandum account. Parties do not object to SoCalGas' requests concerning the EDRMA.

22.3.1.2. Shared O&M

The forecast for CS-OO shared services is \$5.492 million which is \$0.089 million more than 2016 adjusted recorded costs. Shared services consist of three cost categories as shown in the table below.

CS-OO Shared O&M	2019	Change from 2016
Major Market Credit & Collections	\$1,604,000	-\$4,000
Payment Processing	\$3,511,000	\$25,000
Manager of Remittance Processing	\$377,000	\$68,000
Total	\$5,492,000	\$89,000

22.3.1.2.1. Major Market Credit & Collections

Major Market Credit & Collections (MMCC) is responsible for establishing credit, mitigating credit risk, maintaining collateral, negotiating contract credit terms, monitoring accounts receivable, and performing collections activity.

22.3.1.2.2. Payment Processing

This shared services expense covers costs of processing payments mailed to SoCalGas and SDG&E through the USPS as well as electronic payments received through home banking, electronic data interchange, wire transfers and electronic pay programs, including direct, pay-by-phone, and My Account. Additional functions performed by Payment Processing include handling returned checks, investigating payments received without associated account

information, processing of all miscellaneous non-gas revenues, and responding to payment inquiries from banking institutions and authorized payment locations.

22.3.1.2.3. Manager of Remittance Processing

Manager of Remittance Processing is responsible for management of strategy and policy for the overall customer bill presentment and payment processing channels. For customer billing, this includes bill printing and inserting as well as all electronic bill presentment channels. For payment processing, this includes mail, walk-in, and all customer self-service payment channels.

22.3.1.2.4. Discussion

TURN recommends using a three-year average from 2015 to 2017 for the MMCC group resulting in a reduction of \$0.124 million to SoCalGas' forecast. TURN's recommendation is based on the fact that recorded costs in 2016 are higher than 2015 and 2017. However, as argued by SoCalGas, 2015 and 2017 do not accurately reflect costs for this group because of partial vacancies during those two years. Thus, we find SoCalGas' forecast more reasonable than that of TURN's. We also find the forecasts for Payment Processing and Manager of Remittance Processing reasonable which are around 2016 levels. We therefore find it reasonable to adopt SoCalGas' forecast of \$5.492 million for Shared O&M costs which is only slightly higher than base year recorded costs.

22.3.1.3. Uncollectible Rate

SoCalGas is requesting to increase the authorized uncollectible expense rate from the current authorized rate of 0.298 to 0.316 percent based on a five-year average of actual write-offs from 2012 to 2016 to reflect collection practices adopted in recent years while also incorporating cyclical economic

factors, unpredictable and random weather conditions, and natural gas price conditions. TURN recommends that the Commission adopt a 10-year rolling average of historical uncollectible rates starting from 2008 to 2017 with adjustments to occur annually by advice letter to which SoCalGas agrees. We find this approach reasonable and adopt it except that the 10-year period should be from 2007 to 2016 consistent with the 10-year period used to calculate SDG&E's uncollectible rate. In addition, information for 2017 was not yet available at the time this GRC application was filed and the same situation will occur again in SoCalGas' next GRC filing.

As explained by TURN, a rolling 10-year would presumably mitigate some of the risk to both utilities and ratepayers from changing economic conditions which impact the uncollectible rate by allowing the rate to be annually updated as opposed to a single uncollectible rate set for the entire GRC period. Also, this approach captures changes in the utilities' credit and collections activities. The 10-year average for TY2019 is 0.313 percent but should be adjusted to capture the 10-year period from 2007 to 2016. SoCalGas should update the uncollectible rate for PTYs 2020 and 2021 by filing annual Tier 1 advice letters to the Commission's Energy Division.

Incidentally, the above approach was adopted in each of PG&E's last two GRC applications.

22.3.1.4. Capital

As stated above, SoCalGas' forecasts for capital costs are \$13.190 million for 2017, \$12.412 million for 2018, and \$23.663 million for 2019. The table below provides a breakdown of the requested capital costs.

CS-OO Capital SoCalGas	2017	2018	2019
Mandated	\$1,713,000	\$0	\$0
Technical Obsolescence	\$2,513,000	\$307,000	\$102,000
Business Optimization	\$5,934,000	\$2,775,000	\$1,811,000
Improving Customer Experience	\$3,030,000	\$9,330,000	\$21,750,000
Total	\$13,190,000	\$12,412,000	\$23,663,000

22.3.1.4.1. Mandated

There are two projects under Mandated which are the My Account for Specialized Customer Billing System Customer and the SEU CCC GENESYS project. The first project is to enable commercial and industrial business customers access to My Account while the second project addresses issues concerning the call center's ability to service customers as required.

22.3.1.4.2. Technical Obsolescence

There are two refresh projects under this category that are aimed to refresh the current shared enterprise call recording system and to replace the vendor application.

22.3.1.4.3. Business Optimization

There are six projects under this category which are described in Exhibit 130.²⁷⁴ The capital projects include projects to increase collection efficiencies, expand PSI service to multi-family residential builders, install meter transmission units, improve paperless notification of bills, extend workforce technologies, and improve CIS automation.

²⁷⁴ Exhibit 130 at MHB-60 to 64.

22.3.1.4.4. Improving Customer Experience

There are ten projects under this section and each project is described in Exhibit 130.²⁷⁵ Projects include Phases 1 to 3 of the Integrated Customer Data & Analytics (ICDA) which according to SoCalGas will enable it to use customer data to make smarter, faster and better-informed decisions. The ICDA Phase 3 will enhance data analytics themes such as customer consumption profiles, bad debt drivers, and models for self-service.

22.3.1.4.5. Discussion

We reviewed each of the proposed capital projects under CS-OO and find the proposed projects to be reasonable. The projects either address regulatory compliance, address technical obsolescence, optimize business operations, or improve customer service. The forecast costs are supported by evidence submitted in the proceeding. Other parties do not oppose any of the above projects. We find SoCalGas' requested forecasts of \$13.190 million for 2017, \$12.412 million for 2018, and \$23.663 million for 2019 reasonable and authorize them.

22.3.2. SDG&E

SDG&E's CS-OO provides customer service to over three million consumers. Many of the activities and functions performed by SDG&E's CS-OO are similar to those performed by SoCalGas' CS-OO group. SDG&E's O&M forecast for TY2019 is \$44.359 million which is \$7.542 million higher than 2016 recorded costs. For capital costs, SDG&E's forecasts are \$14.897 million for 2017, \$15.774 million for 2018, and \$16.332 million for 2019.

²⁷⁵ *Id.* at MHB-65 to 75.

As was the case with SoCalGas, certain costs are for mitigation of risks identified during the RAMP process. The risks being mitigated are Employee, Contractor and Public Safety and Workforce Planning and RAMP costs total \$0.942 million with \$0.237 million representing incremental RAMP costs for TY2019.

22.3.2.1. O&M Costs

As stated above, SDG&E's forecast for O&M costs is \$44.359 million. The TY forecast incorporates \$0.191 million in savings relating to FOF. The table below summarizes the forecast for the different cost categories and the difference from 2016 costs. All costs are non-shared and all forecasts utilized the base year method with incremental funding requests added to base costs. The figures below reflect updated figures from SDG&E's Update Testimony.

Non-shared O&M CS-OO	TY2019	Change from 2016
Advanced Metering Operations (AMO)	\$10,034,000	\$1,877,000
Billing	\$8,023,000	\$3,760,000
Credit & Collections	\$3,073,000	\$446,000
Remittance Processing	\$738,000	-\$47,000
Postage	\$3,904,000	-\$256,000
Branch Offices	\$2,209,000	\$230,000
CCC Operations	\$10,096,000	\$1,159,000
CCC Support	\$2,679,000	-\$111,000
Customer Operations Support & Projects	\$3,604,000	\$484,000
Total	\$44,359,000	\$7,542,000

22.3.2.1.1. Advance Metering Operations (AMO)

This group supports the delivery of customer services on premises, responds to customer inquiries, and resolves customer issues regarding electric metering issues. Costs include funding to address Workforce Planning to train and develop electric meter testers. Incremental funding of around \$0.993 million

is being requested in connection with support for defaulting of residential customers to Time of Use (TOU).

22.3.2.1.2. Billing

The functions performed are similar to the Billing Services group discussed in the SoCalGas section found in section 22.3.1.1. SDG&E is requesting incremental funding to address a 438 percent growth rate in interval billing relating to TOU. Other incremental funding is also being requested relating to TOU default of residential customers.

22.3.2.1.3. Credit & Collections

The functions performed are similar to the Credit & Collections group discussed in the SoCalGas section. Under this workgroup, SDG&E is also requesting recovery of the current balances tracked under the Residential Disconnection Memorandum Account (RDMA). The RDMA was established pursuant to D.14-06-036 to record unbilled revenue of disconnection-related field visits that were not charged to customers from the establishment of the RDMA in 2014 to December 2015.²⁷⁶ No additional amounts were added to the RDMA balances as the costs being tracked were accounted for in the TY2016 GRC cycle. SDG&E thereafter proposes to close this account.

22.3.2.1.4. Remittance Processing

The functions performed are similar to the Remittance Processing group discussed in the SoCalGas section. SDG&E is also requesting to default non-CARE customers that have a My Account registration and an email to paperless billing.

²⁷⁶ Exhibit 146 at JDS-30.

22.3.2.1.5. Postage

The functions performed are similar to the Remittance Processing Postage group discussed in the SoCalGas section.

22.3.2.1.6. Branch Offices

The functions performed are similar to the Branch Offices group discussed in the SoCalGas section. This section also includes costs for APLs. SDG&E is also requesting closure of two branch offices at the Oceanside and Downtown locations. The Oceanside location is located inside a UPS store under a partnership with SDG&E. SDG&E states that closure of the Oceanside location is involuntary because the lease agreement was terminated by UPS due to co-branding and exclusivity agreements between the UPS franchise and corporate offices.²⁷⁷ On the other hand, SDG&E is requesting closure of the Downtown location due to declining activity and higher costs per transaction.

22.3.2.1.7. CCC Operations

The functions performed are similar to the CCC Operations group discussed in the SoCalGas section.

22.3.2.1.8. CCC Support

The functions performed are similar to the CCC Support group discussed in the SoCalGas section.

22.3.2.1.9. Customer Operations Support Projects

This cost category consists of two groups, Customer Operations Support (COS) and Customer Service Project Management Office (CSPMO). COS is responsible for support and delivery of major Customer Service projects and

²⁷⁷ *Id.* at JDS-39 to 40.

initiatives. CSPMO manages a portfolio of capital and regulatory projects from all Customer Service business units.

22.3.2.1.10. Positions of Intervenors

Comments were provided by ORA, TURN, SDCAN, UCAN, and SBUA.

ORA does not oppose SDG&E's O&M forecasts except for AMO and Billing costs associated with the Residential TOU Default program. ORA recommends 50 percent of the funding requests because the proposed increases for this program are speculative in nature and not based on FTE increases in response to workload. ORA also disagrees with costs to address growth in interval billing accounts recommending two FTEs instead of the 11 proposed by SDG&E.

TURN recommends overall reductions totaling \$4.135 million to SDG&E's O&M forecasts. TURN agrees with ORA's recommended reductions relating to the Residential TOU Default Program and proposes additional reductions based on 2017 recorded costs for AMO and Billing. For Credit & Collections, TURN recommends a two-year average from 2016 to 2017 which results in a slight reduction from SDG&E's forecast. TURN identifies an accounting adjustment of \$7,000 for Remittance Processing which SDG&E agrees to. For Branch Offices and Customer Operations Support & Projects, TURN recommends using a three-year average from 2015 to 2017 and for CCC Support a two-year average. For CCC Operations, TURN recommends a reduction of \$0.195 million based on improved Average Handling Time (AHT) of calls and a six-year average for non-labor costs.

SDCAN agrees with a base year forecast for non-shared costs but recommends disallowance of all incremental costs totaling \$7.5 million. SDCAN further recommends that the Commission require a reduction in customer

complaints in its next GRC before authorizing revenue increases for these cost centers. SDCAN also recommends \$2 million for residential TOU billing costs but on condition that SDG&E add 20 FTEs at an average salary of around \$0.100 million per FTE and that SDG&E file a report about customer billing inquiries and the incidence of billing disputes.

UCAN disagrees with SDG&E's proposal to default all customers to paperless billing starting January 1, 2021, stating that SDG&E has not provided a compelling justification for defaulting customers to electronic billing and that the proposal was made without adequate due diligence. UCAN also recommends the Commission deny SDG&E's request to close Oceanside and Downtown branch offices contending that customers would be adversely affected by the permanent closure of these branches.

SBUA does not make a formal revenue requirement proposal but asks that SDG&E affirmatively state that it is in compliance with customer privacy rules under Public Utilities Code section 8380.²⁷⁸

22.3.2.1.11. Discussion

SDCAN's recommendation to deny all incremental funding totaling \$7.5 million is addressed in the discussion of CCC Operations although it affects five other cost categories that contain incremental funding requests.

Regarding SBUA's concern about compliance with customer privacy laws, SDG&E affirms that it is in compliance with customer privacy rules under Pub. Util. Code § 8380.²⁷⁹

²⁷⁸ Pub. Util. Code § 8380 requires the use of reasonable security procedures to protect customer information held by a utility.

²⁷⁹ Exhibit 149 at JDS-47.

Other issues raised by intervenors are addressed below.

AMO

ORA does not oppose SDG&E's AMO forecasts except for the funding requested in connection with the Residential TOU Default program. ORA agrees that increases are warranted but recommends only 50 percent of SDG&E's requested amount because the proposed increases are speculative in nature and not based on actual workload. TURN agrees with ORA's recommendation and proposes additional reductions based on 2017 recorded costs being less than SDG&E's forecasts.

We reviewed the evidence presented and the arguments raised by the three parties and find that SDG&E based its requested costs for the Residential TOU Default program on its experience with the Small and Medium Business TOU project. Thus, the requests are not without any basis. Regarding the additional reductions proposed by TURN, we find that SDG&E provided reasonable explanation that 2017 recorded costs were slightly lower because projected work was delayed and have been moved to 2018 but SDG&E still needs to perform or complete this work and is committed to doing so. In addition, SDG&E adds that delay in backfilling of vacancies also contributed to the lower costs for 2017.

SDCAN recommends around \$2.0 million for TOU-related activities but we find this request is not supported by sufficient testimony or evidence and also appears to be based on the experience of one customer that changed to TOU in 2017.

Billing

ORA opposes the amounts proposed for growth in interval billed accounts and the Residential TOU Default program and recommends \$2.183 million less

than SDG&E's proposed amount. TURN recommends a reduction of \$1.767 million to SDG&E's request. TURN agrees with ORA's reduction to the Residential TOU Default program but a smaller reduction for interval billing. TURN adds a \$55,000 reduction to additional work to be performed by a new business systems analyst.

However, we find that SDG&E's request for an additional 15.5 FTEs for the Residential TOU Default program was adequately based on its experience with the Small and Medium Business TOU project and is not without basis contrary to what ORA and TURN allege. Regarding the additional funding for Interval Billing, we find that SDG&E's forecast takes into account funding necessary to address a 438 percent growth rate in interval billing relating to TOU. Thus, we find the above amounts requested by SDG&E to be reasonable and adequately supported by the evidence presented. We agree with TURN's adjustment concerning an additional FTE for a new business systems analyst. SDG&E justifies the additional FTE because of an additional 10 percent of work that needs to be performed. But because there are only three FTEs for this work, an additional 10 percent of work does not equal one additional FTE and we accept TURN's recommended increase of 0.4 FTEs which equals a \$55,000 reduction to SoCalGas' forecast for Billing.

Credit & Collections

We find SDG&E's base year method appropriate and that TURN's recommendation to use a two-year average does not take into account vacancies in 2017. We also find SDG&E's request to recover current balances as of December 31, 2018 under the RDMA reasonable and they should be approved as well as SDG&E's request to thereafter close the account. Parties do not object to SDG&E's requests relating to the RDMA.

Remittance Processing

TURN identified an accounting adjustment requiring a reduction of \$7,000 which SDG&E agrees to. With respect to defaulting non-CARE customers to paperless billing, we agree with UCAN that SDG&E did not provide clear and compelling evidence that justifies approval of this proposal. SDG&E mentioned surveys showing that many customers receiving paper billing pay online and reasons why these customers pay online.²⁸⁰ However, we find that the survey questions and information are geared towards those who already pay online. There are also no questions shown relating to whether customers prefer paper or online billing or if paper-billed customers approve of being defaulted to paperless billing or not receiving paper bills anymore. Based on the above, we find that SDG&E's forecast should be reduced by \$7,000 and that there is insufficient information within which to grant SDG&E's request to default non-CARE customers to paperless billing at this time.

Postage

We find the forecast for Postage costs to be reasonable and it takes into account declining postage costs. Parties generally do not oppose SDG&E's forecast for Postage.

Branch Offices

We agree with SDG&E's use of a base year forecast methodology and find that TURN's recommendation to use a three-year average from 2015 to 2017 does not take into account vacancies in 2015 and 2017. Thus, we agree with SDG&E's forecast.

²⁸⁰ Exhibit 149 at JDS-29 to 30.

Regarding the proposed closure of the Oceanside and Downtown branches, we find the requests to close the Oceanside branch should be approved while closure of the Downtown branch should be rejected at this time. For the Oceanside branch, the closure is involuntary due to the termination of the lease agreement with UPS where the branch was located. SDG&E also presented evidence showing that customers that utilized this branch have managed to find alternatives for payment and other needs and that no complaints have been received regarding the closure of the Oceanside branch. For the Downtown branch, SDG&E presented testimony showing that approximately 96 percent of transactions in branch offices are payment transactions which can be serviced by APLs. However, this information is for all branch offices and not specifically with regards to the Downtown branch. There is also no evidence showing input from customers of the Downtown branch such as surveys or other means and insufficient evidence concerning non-payment transactions at the Downtown branch and whether these can be serviced by other means. Thus, we find it reasonable to deny SDG&E's request to close the Downtown branch at this time. The economic reasons for closing this branch are well supported but the service-related reasons are insufficient.

CCC Operations

TURN proposes a reduction of \$0.195 million because of improved AHT to resolve calls and a reduction of \$88,000 using a six-year average for non-labor. However, while recorded AHT for 2017 was 10 seconds faster, the volume of calls increased by around 50,000²⁸¹ which offsets the reduced AHT for calls. For

²⁸¹ Exhibit 149 Table JS-21 at JDS-43.

non-labor costs, we find that a base year method is more appropriate to align with the base year forecast for labor costs. According to SDG&E, non-labor expenses under this category are specific and defined for individual work items.

SDCAN's recommendation appears to be based on the number of customer complaints as it states that the number of informal complaints filed with the Commission's Consumer Affairs Branch (CAB) increased in 2015 to 2017 as opposed to the number of complaints in 2007, 2008, and 2009. We find that SDCAN's recommendations are not substantiated as the funding requests it opposes have no direct bearing on the number of customer complaints filed with CAB. The incremental funding requests are for a variety of specific activities involving different work groups which SDG&E does not challenge. Also, complaints raised with CAB presumably do not involve only issues pertaining to CS-OO activities. Lastly, as shown by SDG&E, the number of complaints in 2017 was 273 compared to 310 in 2009. Thus, we find SDCAN's recommendation to be without merit. For the same reason, we find it improper to base funding levels for the next GRC on the number of customer complaints filed with CAB although improving customer service to reduce the number of complaints and adequately resolving complaints within reasonable timeframes should be part of SDG&E's goals.

Based on the above, we find SDG&E's forecast for CCC Operations reasonable and should be approved.

CCC Support

Similar to our finding in Credit & Collections, we find SDG&E's base year method appropriate and that TURN's recommendation to use a two-year average does not take into account vacancies in 2017.

Customer Operations Support & Projects

We reviewed TURN's recommendation to use a three-year average from 2015 to 2017 but find that 2015 does not capture the labor increase in 2016 due to the transition of ongoing Dynamic Support from capital to O&M and that 2017 costs do not consider returning employees because of partial leaves reflected in that year. Thus, we find SDG&E's forecast should be approved.

Summary of O&M costs

Summarizing the above discussions, we find SDG&E's O&M forecasts reasonable and should be approved subject to adjustment reductions of \$55,000 for Billing and \$7,000 for Remittance Processing. Recovery of the current balance under the RDMA of \$0.92 million is authorized as well as the request to thereafter close the account. Closure of the Oceanside branch is authorized but the request to close the Downtown branch is denied at this time. The request to default to paperless billing is likewise denied at this time.

22.3.2.2. Uncollectible Rate

SDG&E is proposing an uncollectible rate of 0.174 percent based on a 10-year average from 2007 to 2016 consistent with how the uncollectible rate for the last two GRCs were calculated.²⁸² TURN recommends using a 10-year rolling average from 2008 to 2017 which SDG&E opposes saying that annual advice letter filings would be unduly burdensome.

We make the same findings and conclusions as we did in the SoCalGas portion under section 22.3.1.3 and agree with TURN that a 10-year rolling average is more appropriate and mitigates some of the risk from changing

²⁸² Exhibit 146 at JDS-61.

economic conditions which impact the uncollectible rate and captures changes in the utilities' credit and collections activities. However, we agree with SDG&E that the 10-year period should be calculated from 2007 to 2016. SDG&E should update the uncollectible rate for PTYs 2020 and 2021 by filing annual Tier 1 advice letters to the Commission's Energy Division.

22.3.2.3. Capital

As stated above, SDG&E's forecasts for capital costs are \$14.897 million for 2017, \$15.774 million for 2018, and \$16.332 million for 2019. The table below provides a breakdown of the requested capital costs.

CS-OO Capital SDG&E	2017	2018	2019
Mandated	\$3,340,000	\$2,480,000	\$1,505,000
Technical Obsolescence	\$1,494,000	\$6,092,000	\$10,827,000
Business Optimization	\$559,000	\$0	\$0
Improving Customer Experience	\$9,504,000	\$7,202,000	\$4,000,000
Total	\$14,897,000	\$15,774,000	\$16,332,000

22.3.2.3.1. Mandated

There is one project under Mandated which aims to provide enhancements and additional features to NEM billing to ensure accurate and timely bills.

22.3.2.3.2. Technical Obsolescence

There are two capital projects under Technical Obsolescence. The Smart Meter Systems Upgrade will provide upgrades to the smart meter database hardware while the Electronic Bill Presentment and Payment Technology (EBPP Tech) will re-engineer the EBPP resulting in increased functionality.

22.3.2.3.3. Business Optimization

There are 12 capital projects under this category and each project is described in Exhibit 146.²⁸³ Projects include improvements to FOF, account management and billing system enhancement, centralizing the calculation engine that provides bill impacts, building a smart meter analytics platform, a rebuild of the remote meter configuration, enhancements to the smart meter network communication, and purchasing and replacing branch office kiosks.

22.3.2.3.4. Improving Customer Experience

There are three projects under this category which include building an analytical test bed that will create business efficiencies utilizing automation, enhancing the self-service capabilities of the IVR, and phase 2 of the Bill Redesign project.

22.3.2.3.5. Position of Intervenors

Comments were filed by NDC, UCAN and SCGC.

NDC recommends disallowance of the Branch Office Kiosk Replacement project because SDG&E has not justified the costs for this project. NDC adds that the kiosks will only add to annual expenses. As an alternative, NDC proposes authorizing \$0.150 million for a phase 1 of the project.

UCAN recommends that funding Bill Redesign project funding be reduced to \$0.8 million total for 2017 and 2018 and zero funding for 2019. UCAN argues that the proposed Bill Redesign project is similar to and has significant overlaps with the 2016 Bill Redesign Project.

²⁸³ *Id.* at JDS-68 to 73.

SDG&E disagrees with UCAN that there was overlapping scope. The two projects had different scopes of functionality with the first project based on email notification and the second based on changes to paper bill.

22.3.2.3.6. Discussion

We reviewed SDG&E's proposed capital projects under CS-OO and find the proposed projects to be reasonable. Similar to the CS-OO capital projects proposed by SoCalGas, SDG&E's projects either address regulatory compliance, address technical obsolescence, optimizes business operations, or improves customer service. We find SDG&E's proposed projects to be supported by evidence submitted and find the proposed forecasts to be reasonable.

Regarding the Branch Office Kiosk Replacement project, SDG&E provides that the current kiosks are inoperable as their useful life of 12 years has already passed. SDG&E adds that the kiosks make payments easier and provide more options for customers that conduct transactions at branch offices. The new kiosks will also include enhanced functionalities such as account look-up and credit and debit card payment processing. We reviewed the arguments raised by both SDG&E and NDC and agree with SDG&E that the kiosks provide enhanced services to customers and provide convenient methods to make payments. SDG&E provides a calculation showing the difference between including and excluding avoided labor costs in Table JS-26 of Exhibit 149.²⁸⁴ However, SDG&E's calculation does not consider the equivalently avoided capital costs as argued by NDC. In order to facilitate the deployment of new kiosks and realize associated benefits, but limit rate increases to just and reasonable amounts, we

²⁸⁴ Exhibit 149 at JDS-57.

find it reasonable to approve funding for the new kiosks that will not result in any net increase in costs over use of the existing kiosks. This assumes a \$0.312 million annual maintenance expense for the new kiosks and a total capital budget of \$1.106 million. This results in a reduction of \$0.881 million in 2018 from SDGE's request of \$1.987 million.

Regarding UCAN's objections to the Bill Redesign project, we find that SDG&E was able to sufficiently distinguish the proposed project from the Bill Redesign Project in 2016. SDG&E explains that the earlier project was re-scoped into multiple phases due to the complexity of the proposed project and Phase 1 of the project focused on enhancements relating to email notifications while the current phase being proposed focuses on redesigning the paper bill mailed to customers.²⁸⁵ Thus, we find that the proposed project should be approved.

Based on the discussion above, we find SDG&E's proposed CS-OO capital projects reasonable and find that the requested forecasts of \$14.897 million for 2017, \$15.774 million for 2018, and \$16.332 million for 2019 should be authorized subject to a reduction of \$0.881 million in 2018 based on the reduction in funding for the branch kiosk project.

22.4. Customer Services Information

Customer Services Information provides customer service through multiple channels with solutions to enhance the ability of SoCalGas' customers to understand and manage their energy usage.²⁸⁶ Services include customer communication, research, outreach and education, account management

²⁸⁵ *Id.* at JDS-59 to 60.

²⁸⁶ Exhibit 156 at ASC-1.

services, services for low-income and disadvantaged customers, and efforts to reduce GHG emissions and improve local air quality through supporting clean transportation and renewable gas option. This section only applies to SoCalGas as related services provided by SDG&E are included in the next Customer Service section (Customer Services Information and Technologies).

22.4.1. O&M Costs

The TY2019 forecast for O&M costs is \$24.985 million²⁸⁷ which is \$7.159 million more than 2016 adjusted, recorded expenses. SoCalGas' O&M costs include both shared and non-shared services.

Certain costs are driven by risk mitigation activities to mitigate Employee, Contractor, Customer, and Public Safety. The primary mitigation activity to be conducted is Natural Gas Appliance Testing (NGAT) services and the estimate of costs for TY2019 is \$2.726 million. The estimate is based on the number of homes that will likely require NGAT services. These RAMP costs are reviewed as part of our review of proposed O&M costs.

Savings totaling \$1.037 million from FOF are included in the forecast. And pursuant to D.16-06-054, the forecast costs do not include costs from the Aliso Canyon gas leak incident and these costs have also been removed from historical information.

22.4.1.1. Non-Shared O&M

The total forecast for non-shared costs is \$20.515 million which is \$4.992 million higher than 2016 costs. Non-shared O&M cost categories are composed of three categories and the table below shows the forecast for each cost

²⁸⁷ This amount was adjusted from \$25.048 million to reflect an adjustment in SoCalGas' non shared costs which were adjusted due to a calculation error.

category. All costs were forecast using a five-year historical average plus incremental additions.

Non-shared O&M	TY2019 ²⁸⁸	Change from 2016
Customer Strategy and Engagement	\$7,098,000	\$1,914,000
Customer Assistance	\$3,435,000	\$1,467,000
Customer Segment Services	\$9,982,000	\$1,611,000
Total	\$20,515,000	\$4,992,000

22.4.1.1.1. Customer Strategy and Engagement

The Customer Strategy and Engagement (CSE) group is responsible for managing customer communications across all mediums and segments and includes: (a) providing prompt communication to customers to build awareness and access to existing programs and new services; (b) educating customers and stakeholders about energy management; (c) billing and payment options, rebate programs, and natural gas safety, conducting customer research; and (d) enforcing web access standards to ensure that documents on the website are accessible through standard accessibility tools.

22.4.1.1.2. Customer Assistance

Customer Assistance Programs cover costs for the administration of assistance programs offered to residential customers with limited income and certain medical conditions. These programs offer certain services at no cost, offer natural gas services of reduced rates, or provide bill payment assistance to qualified customers.

²⁸⁸ The TY2019 values were adjusted in Exhibit 158 at RM-7 to reflect calculation adjustments after errors were discovered.

22.4.1.1.3. Customer Segment Services

The Customer Segment Services group is responsible for providing individualized account management of customer segments to ensure that relevant information, services, products, programs, and other services are provided to help meet customers' energy needs.

22.4.1.2. Shared O&M

The forecast for shared services costs is \$4.490 million which is \$2.187 million higher than 2016 recorded costs. Shared services consist of two cost categories as shown in the table below.

Shared O&M	2019	Change from 2016
Clean Transportation	\$3,536,000	\$1,656,000
Renewable Customer Gas Outreach	\$954,000	\$531,000
Total	\$4,490,000²⁸⁹	\$2,187,000

22.4.1.2.1. Clean Transportation

This group provides clean transportation services to customers. The group ensures that SoCalGas is able to meet demand for and market adoption of natural gas as a source of transportation fuel in support of California's GHG reduction goals. Costs were forecast using a five-year historical average for customer support activities and a base year method for customer outreach activities plus incremental adjustments to support additional FTEs that are needed to help manage clean transportation needs. SoCalGas states that demand continues to increase for these services.

²⁸⁹ This amount was adjusted to \$4.470 million to reflect errors discovered while responding to data requests.

22.4.1.2.2. Renewable Customer Gas Outreach

According to SoCalGas, California law provides for the active support of renewable gas market development activities and this group provides support for the implementation of renewable gas projects. Costs were forecast using a three-year historical average because this period is more reflective of future costs.

22.4.1.3. Position of Intervenors

ORA, NDC and SBUA provided comments to SoCalGas' Non-shared O&M forecasts.

ORA recommends a reduction of \$1.158 million to Customer Strategy and Engagement Expenses and states that certain incremental activities are for improving SoCalGas' public relations and image and that these costs should not be borne by ratepayers.

NDC supports SoCalGas' minority communication campaign analysis but recommends that SoCalGas conduct its multicultural and language surveys annually.

SBUA recommends that SoCalGas commit to fund at least 10 FTEs that are trained to support small businesses and create a department that will promote policies to improve service for small businesses. Finally, SBUA recommends that Sempra be required to conduct a detailed study and report on challenges and hurdles faced by small commercial customers in adopting energy solutions.

22.4.1.4. Discussion

ORA objects to incremental spending for additional FTEs and activities under Customer Strategy and Engagement Expenses and states that these activities provide no benefit to ratepayers and are mostly for building SoCalGas' image. However, we find SoCalGas' rebuttal testimony sufficiently explains that the incremental expenses are driven by additional spending on climate change

education and informing customers of resources available to support how to cope with and address the effect of climate change such as using energy efficient appliances, lower and zero-emission vehicles, etc. The incremental costs will also fund additional graphic services necessary for the increased communications activities and enhanced research and analysis for better information on customer communications preferences, service offerings, and trends.

Regarding NDC's request, SoCalGas states that it already conducts Spanish language qualitative research to gain a better understanding of this minority segment and plans to conduct this analysis annually which we find satisfies NDCs request.

Regarding SBUA's proposals, we find that SBUA did not provide sufficient testimony or other evidence to support its recommendation for at least 10 additional FTEs to be trained to target the needs of the small business community. SoCalGas' requests include a request for one additional FTE to support its customer segment services. With respect to the study proposed by SBUA, SoCalGas states that it already conducts an energy efficiency marketing and outreach campaign and that it regularly conducts business customer panels to understand the needs and interests of small and medium business customers.²⁹⁰ Thus, we find that SBUA's request is not necessary at this time.

Parties do not object to SoCalGas' Shared Services forecasts which we reviewed and find reasonable based on the evidence presented. The requested amount of \$4.490 million was corrected to \$4.470 million to reflect errors identified while responding to data requests.

²⁹⁰ Exhibit 158 at RM-24 to 25.

Based on all of the above, we find SoCalGas' forecast of \$24.985 million for O&M costs to be reasonable and should be approved.

22.4.2. Capital

For capital costs, SoCalGas is requesting \$4.464 million for 2017, \$6.510 million for 2018, and \$12.483 million for 2019. The table below provides a breakdown of the requested capital costs.

Capital	2017	2018	2019
Data Driven Customer Communications	\$0	\$2,218,000	\$2,202,000
My Account Additional Self-Service Features	\$0	\$934,000	\$6,343,000
My Account Customer Engagement Improvements	\$0	\$1,381,000	\$2,072,000
Optimizing Self-Service Payment Extensions	\$0	\$486,000	\$0
My Account Alignment	\$0	\$940,000	\$1,866,000
Customer Experience	\$3,287,000	\$0	\$0
AB 802 Building Benchmarking	\$611,000	\$0	\$0
GT-NC Rate Changes	\$476,000	\$551,000	\$0
Transactional and Regulatory	\$90,000	\$0	\$0
Total	\$4,464,000	\$6,510,000	\$12,483,000

22.4.2.1. Data Driven Customer Communications

All residential customers are currently receiving similar emails for each transactional or marketing email campaign and this project will deliver more relevant and personalized emails to various customer segments.

22.4.2.2. My Account Additional Self-Service Features

This project will facilitate customer self-service by removing interface and system dependencies to CIS.

22.4.2.3. My Account Customer Engagement Improvements

The project will streamline the process to register into SoCalGas' My Account system, simplify standard online tasks, and improve customer online security.

22.4.2.4. Optimizing Self-Service Payment Extensions

This project will allow more payment arrangements and payment extensions by revising current billing and payment rules in the CIS system.

22.4.2.5. My Account Alignment

This project will combine the interface between the My Account website and SoCalGas' main website, improve the design for both websites, and increase information available to customers.

22.4.2.6. Customer Experience

This project will provide reductions to customer efforts in making service requests and finding information and promote the use of self-service systems and functions. The project will also increase enrollment into the My Account system by allowing enrollment while on the telephone.

22.4.2.7. AB 802 Building Benchmarking

This project is required to meet data and process requirements mandated by AB 802 to establish a new statewide energy use benchmarking.

22.4.2.8. GT-NC Rate Changes

SoCalGas is mandated to implement a new tariff (Schedule No. GT-NC) to modify existing rules relating to service interruptions.

22.4.2.9. Transactional and Regulatory

This project will upgrade the current content management system used to manage all text, image, and content on SoGalGas' website.

22.4.2.10. Discussion

We reviewed each of the above capital projects under Customer Services Information and find the proposed projects to be necessary. SoCalGas' forecast methodologies and forecast costs are reasonable and supported by the evidence presented in this proceeding. The above projects support improvements and upgrades to SoCalGas' website and the My Account system and aim to improve customer access to services and information and ease of use. Other projects are mandated by law or regulations. Parties do not oppose any of the above projects.

Based on the above, we find that SoCalGas' requested forecasts \$4.464 million for 2017, \$6.510 million for 2018, and \$12.483 million for 2019 are reasonable and should be authorized.

22.5. Customer Services Information and Technology

This section applies only to SDG&E as related services provided by SoCalGas are included in Customer Service Information which was discussed in section 22.4.

Customer Service Information and Technologies (CS-IT) provides efficient, effective, and reliable customer service to SDG&E's 3.6 million customers. SDG&E's requested funding supports its goal of providing safe, reliable, and efficient gas and electric service, and serving as trusted energy advisor to customers by offering relevant information about their energy consumption, pricing plans, and programs and tools to manage and control their use. The funding for CS-IT will also allow SDG&E to provide customers with residential customer services, business services, marketing and communications, research and analytics, customer programs, and customer pricing, among other services.

The forecast includes incremental RAMP funding of \$0.241 million to mitigate Employee, Contractor, and Public Safety risks in addition to 2016

embedded costs of \$0.693 million. The forecast also incorporates \$0.922 million in savings due to FOF.

22.5.1. O&M Costs

SDG&E’s TY2019 forecast for CS-IT O&M costs is \$26.401 million which is \$4.314 million higher than 2016 adjusted, recorded expenses. O&M costs include both shared and non-shared services.

SDG&E’s forecast supports the following activities: (a) system upgrades, research and rate education; (b) support for the wide array of business customers’ energy needs; (c) expansion of research and communication to engage customers in diverse and disadvantaged communities; (d) customer privacy and data access initiatives to comply with new regulations; (e) increased support for rate design strategy, rate changes, and impacts; (f) expansion of clean transportation programs in support of ambitious state greenhouse gas reduction goals; (g) NGAT and seasonal safety communications; and (h) optional efficiency projects.

All O&M costs were forecast using a base year method to represent the appropriate starting point to calculate projected expenses for TY2019. Where appropriate, incremental costs were added to the base costs.

22.5.1.1. Non-shared O&M

The total for non-shared O&M costs is \$26.058 million which is \$4.314 million higher than 2016 recorded costs. The table below provides a summary of the non-shared O&M costs:

Non-shared O&M CS-IT	TY2019	Change from 2016
Residential Customer Services	\$6,267,000	\$1,005,000
Business Services	\$4,812,000	-\$225,000
Marketing, Research & Analysis	\$8,574,000	\$2,355,000
Customer Programs, Pricing, and Other Office	\$6,405,000	\$1,179,000

Total	\$26,058,000	\$4,314,000
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22.5.1.1.1. Residential Customer Services

The Residential Customer Services (RCS) department is responsible for services and activities focused on delivering and enhancing overall customer experience. RCS aims to provide consistent, timely, efficient, and responsive service to customers as well as anticipate customer needs to proactively. The key subgroups within the RCS department are: (a) Residential Outreach; (b) Office of Customer Experience; (c) Clean Transportation; (d) CCC; and (d) Branch Offices.

There are two existing memorandum accounts under the RCS, the Alternative Fuel Vehicle Memorandum Account (AFVMA) and the Energy Data Request Memorandum Account (EDRMA).

The AFVMA was established pursuant to D.13-11-002²⁹¹ to record costs related to the implementation of sub-metering pilots that are in excess of what could reasonably be recovered through the Electric Program Investment Charge (EPIC). Costs recorded in the AFVMA cannot exceed \$2 million or \$5 million if EPIC costs are not authorized. SDG&E requests recovery of the AFVMA balances and upon approval, requests that the account be closed.

On the other hand, the EDRMA was established pursuant to D.14-05-016²⁹² to record costs associated with developing processes and technologies and providing labor to support functions and activities related to managing Energy Data Access Rules. SDG&E requests recovery of the EDRMA balance. Upon approval, SDG&E also requests that the EDRMA be closed.

²⁹¹ D.13-11-002 OP 7.

²⁹² D.14-05-016 OP 13.

22.5.1.1.2. Business Services

Business Services provides customer-focused education, expertise, and analysis surrounding energy rates, tariff services, energy efficiency, demand response, safety, and regulatory information through various channels. Business activities are broken down into two functional areas: (a) Business Account Management which provides services to all business customers; and (b) Customer Services Staff Support which provides specialized assistance and expertise in many different areas including infrastructure project coordination, billing assistance services reliability information, rate analysis, technical assistance on end use equipment, development of outreach tools and materials, and employee and customer education and materials and training.

Certain costs are driven by AB 802 and CEC Commercial Benchmarking regulations. SDG&E requests \$0.180 million to comply with these regulations which include license fees, monthly maintenance and hosting costs, and necessary enhancements to the systems. AB 802 was established to provide building owners with the ability to request and obtain energy usage data so they can benchmark their buildings. The AB 802 Commercial Benchmarking Memorandum Account was established to track costs associated compliance and SDG&E requests recovery of electric and gas balances under the account. Upon approval, SDG&E requests that the account ne closed.

22.5.1.1.3. Marketing, Research, and Analysis

Marketing, Research and Analysis (MRA) is responsible for a wide variety of activities which include developing strategic marketing plans, execution of communication tactics across various channels, oversight and management of SDG&E's website, conducting qualitative and quantitative customer research

and analytics, and supporting statewide collaboration and education about safety and emergency preparedness.

The Rate Reform Memorandum Account (RRMA) was established pursuant to D.15-07-001²⁹³ to track verifiable incremental costs in the following categories: (a) TOU pilots; (b) TOU studies; (c) marketing, education, and outreach costs associated with the rate changes approved in D.15-07-001; and (d) other reasonable expenditures as required to implement the decision. SDG&E requests recovery of balances under the RRMA.

22.5.1.1.4. Customer Programs, Pricing, and Other Office (CP&P)

CP&P includes the Customer Services VP and three groups: Customer Assistance Program (CAP); Customer Solutions; and Customer Pricing. These groups are collectively responsible for analytical, technical, and policy support for development of value-added customer solutions as well as rate design, strategy, electric load analysis, and demand forecasting.

22.5.1.2. Shared O&M

The forecast for CS-IT shared services is \$0.343 million which is the same level of funding as 2016 recorded costs. Shared services consist of two cost categories as shown in the table below.

22.5.1.2.1. Business Strategy and Development

Business Strategy and Development is comprised of various external information services used across the company. These services are utilized to conduct research on market and industry trends, and business model and

²⁹³ D.15-07-001 OP 12.

technology innovations in the power and utility sectors, benchmarking analyst reports, forecast of energy supply, demand and pricing, and other related topics.

22.5.1.2.2. Low Emission Vehicle Program

Low Emissions Vehicle Program supports SDG&E's and SoCalGas' Low Emissions Vehicle programs and provides Natural Gas Vehicle (NGV) utility account management, customer information, education, and training services to the general public, operators of NGVs and NGV refueling stations, government agencies, and other groups.

22.5.1.3. Positions of Intervenors

ORA, UCAN, NDC and SBUA provided comments to SDG&E's Non-shared and Shared O&M forecasts.

ORA recommends \$6.131 million for RCS which is slightly below SDG&E's forecast based on its proposal for 3.4 additional FTEs instead of the 4.7 requested by SDG&E for the expansion of the Clean Transportation program. ORA also objects to the incremental \$1.7 million for Rate Education & Outreach under MRA expenses stating that this represents unprecedented level of spending for this function. Finally, ORA objects to the proposed increase of \$0.341 million for regulatory compliance in Customer Pricing for lack of basis and because SDG&E did not identify specific increases in legislative and regulatory requirements to justify SDG&E's request.

UCAN recommends that SDG&E's request for \$1.7 million in incremental funding for rate education be denied and adds that all spending on Residential Rate Reform marketing, education and outreach should be included in the RRMA and considered a part of SDG&E's overall \$19.4 million budget authorization for that purpose.

NDC proposes that SDG&E include Spanish communities in its proposed multicultural and language survey as well as discuss survey results with SoCalGas, NDC, and other minority serving organizations to better inform these groups about the proposed multicultural campaign. NDC also proposes that previously unused for rate reform outreach be used to offset the requested budget for the MRA.

SBUA recommends an additional \$0.225 million for Business Services to add two FTEs to serve as customer service representatives specifically trained to service small business customers. SBUA also proposes that SDG&E be required to fund at least 10 FTEs that are trained and specifically dedicated to supporting small businesses with customer service. Lastly, SBUA proposes that SDG&E be required to affirm that it is in compliance with privacy laws.

22.5.1.4. Discussion

Regarding the Clean Transportation program under RCS, SDG&E presented five different positions having various duties to support the program. ORA objects to having fractional FTEs for these positions and instead recommends that each position be performed by one FTE each. However, we agree with SDG&E that it is sometimes necessary for an FTE to perform multiple functions resulting in fractional FTEs for some positions. SDG&E identified the incremental functions that will be performed to support its request for the additional FTEs being requested and we take no issue with FTEs performing different functions resulting in fractional FTEs for several positions. Because this was ORA's only objection to the requested amount for Clean Transportation, we find it reasonable to adopt SDG&E's forecast of \$6.267 million for RCS.

SBUA's proposal to fund at least 10 additional FTES to be trained to target the needs of small business was addressed in CS Information in section 24C.1.4

where we found that SBUA did not provide sufficient testimony or other evidence to support its recommendation for the additional FTEs. SDG&E states that it already has specialists, account executives, and energy advisors that can address the specific needs of small businesses²⁹⁴ and SBUA has not demonstrated that these are insufficient or that additional funding is needed. We make the same finding above regarding the request for two FTEs under Business Services. Regarding an affirmative statement concerning compliance with privacy laws, SDG&E affirmatively states that it complies with privacy laws in Exhibit 153 and addresses a specific issue that SBUA is concerned with. We find that this affirmation is sufficient. Based on the above, we find no compelling need to adjust SDG&E's requested amount of \$4.812 million for Business Services.

ORA, UCAN, and NDC oppose the requested funding of \$1.7 million for Rate Education and Outreach under Marketing, Research, and Analysis. ORA proposes to use the four-year average of costs for Rate Education and Outreach from 2013 to 2017 while UCAN proposes that the entire amount be disallowed because these outreach efforts should already be included in the funding covered by the Rate Reform Memorandum Account. On the other hand, NDC states that unused funding from prior years that were not spent should be used to fund this activity. SDG&E states that 2016 had unusually low costs because rate reform had progressed more slowly in 2016 and communication anticipated in 2016 began in mid-to-late 2017.²⁹⁵ SDG&E also explains that Rate Education and Outreach activities will educate customers about the changing landscape of

²⁹⁴ Exhibit 153 at LCD-20 to 21.

²⁹⁵ *Id.* at LCD-7 to 8.

energy pricing and new rate options and also provided more specific details about the types of outreach and education that will be included to distinguish these from what is covered by education under the Rate Reform Memorandum Account which will focus on the impacts of TOU transition for residential customers.

However, recorded costs have been decreasing each year from \$1.941 million in 2013, \$1.501 million in 2014, \$0.804 million in 2015, and \$0.306 million in 2016.²⁹⁶ SDG&E states that it spent \$1.2 million in 2017 and expects rate education efforts to continue increasing although part of the spending is likely due to decreased spending in 2016 because of delayed implementation of activities that were anticipated for 2016 as SDG&E itself indicated. In addition, spending in 2017 is still below SDG&E's forecasted costs for 2017 of \$1.5 million despite implementation of 2016 activities in 2017. Based on the above, we find it more appropriate to apply recorded costs in 2017 of \$1.2 million for Rate Education and Outreach activities. This level of funding recognizes increased activities that SDG&E is anticipating but also recognizes 2016 recorded costs as well as activities planned for 2016 but were not implemented until 2017. This results in a reduction of \$0.5 million to SDG&E's forecast for Marketing, Research, and Analysis resulting in a total of \$8.074 million that should be approved.

Regarding ORA's objection to the requested costs for regulatory compliance under Customer Pricing, SDG&E states that the number of active proceedings has increased significantly from 18 in 2012 to 2014 to 38 in 2015 to

²⁹⁶ *Id.* at Table LD-4 at LCD-8.

2017.²⁹⁷ SDG&E states that these proceedings require analysis, support, input, and oversight from the Customer Pricing group. Based on the above, we find SDG&E's proposed costs for Customer Pricing of approximately \$0.332 million is supported by the evidence presented. Therefore, we find that SDG&E's request of \$6.405 million for Customer Programs, Pricing, and Other Office is reasonable and should be approved.

Regarding SDG&E's request for Shared Services, SDG&E's requested amount of \$0.343 million is equal to recorded costs in 2016 and we find the request reasonable and should be approved.

We reviewed SDG&E's requests for recovery of account balances under the AFVMA and the EDRMA and find the requests of the balance as of December 31, 2018 to be reasonable. AFVMA is for costs relating to the implementation of sub-metering pilots that are in excess of what could be recovered under EPIC. On the other hand, EDRMA is for costs associated with developing processes and technologies and providing labor to support functions and activities related to managing Energy Data Access Rules. We also find the requests to close these two accounts reasonable and these requests should be approved.

We reviewed the request to recover balances under the AB802MA and find recovery of the balance as of December 31, 2018 to be reasonable and should be approved as well as to thereafter close the account.

We also reviewed recovery of account balances under the RRMA and find recovery of the balance as of December 31, 2018 to be reasonable and should be

²⁹⁷ *Id.* at LCD-10.

approved. The RRMA records costs relating to TOU pilots, studies, marketing, and education as authorized under D.15-07-001. SDG&E requests continuation of the RRMA which we also approve.

22.5.2. Capital

For capital costs, SDG&E requests \$20.583 million for 2017, \$21.109 million for 2018, and \$1.818 million for 2019. The table below provides a breakdown of the requested capital costs.

Capital	2017	2018	2019
Business Optimization	\$517,000	\$617,000	\$643,000
Improving Customer Service	\$1,826,000	\$1,387,000	\$310,000
Mandated	\$18,240,000	\$19,110,000	\$865,000
Total	\$20,583,000	\$21,109,000	\$1,818,000

22.5.2.1. Business Optimization

Projects under Business Optimization include Phase 1 and 3 of the Demand Response Management System (DRMS) project. The DRMS project will enable management of SDG&E’s demand response portfolio with the following integrated capabilities: program, management; enrollment; eligibility; device management; event management; forecasting; settlement; analytics/reporting; and workflow.

22.5.2.2. Improving Customer Service

There are three projects under this category which are: (a) the My Account Reliability & System Investigation Request Bundled Work which is for minimizing My Account outages and for maximizing the ability to monitor and communicate system operations; (b) the Customer Authorization Project which will streamline the existing disparate process for handling letters of authorization and associated requests for customer data; and (c) the Gas Customer Choice Automation which will provide some automation to the gas imbalance reporting and curtailment processes.

22.5.2.3. Mandated

There are six projects under Mandated that are necessary to comply with requirements under the TOU Pilot Program, the GRC Phase 2, and AB 802 Benchmarking requirements. Many of the projects include redesign and increased functionality of SDG&E's customer and billing systems to comply with requirements under the above programs.

22.5.2.4. Discussion

We reviewed each of the above capital projects and find the proposed projects to be necessary and the proposed costs to be reasonable. All the capital projects are IT-related upgrades to improve capabilities relating to SDG&E's demand response portfolio, to improve the My Account system, and for increased functionality to comply with TOU and AB 802 Commercial Benchmarking regulations. Parties do not oppose any of SDG&E's capital forecast. Therefore, we approve the requested forecasts of \$20.583 million for 2017, \$21.109 million for 2018, and \$1.818 million for 2019.

22.6. Customer Service Technologies, Policies, & Solutions

Customer Service Technologies, Policies & Solutions (CS-TPS) comprise a group of functions and activities that promote the development and implementation of technologies and policies that optimize the use of natural gas as an environmentally beneficial and cost-effective energy solution. This section only applies to SoCalGas and includes only O&M costs.

SoCalGas' TY2019 forecast for CS-TPS O&M costs is \$19.234 million which is \$4.608 higher than 2016 adjusted, recorded expenses and includes both non-shared and shared services.

According to SoCalGas, a major focus of CS-TPS is to advance and support California's environmental quality, and public health and safety goals. These

goals include reducing GHG emissions, attaining Clean Air Act standards for particulate matter and smog-causing pollutants, and achieving other environmental and customer policies.

Pursuant to D.16-06-054,²⁹⁸ costs relating to the Aliso Canyon gas leak incident have been removed from the forecast and from historical costs.

22.6.1. Non-Shared O&M

The TY2019 forecast for non-shared O&M costs is \$15.226 million which is \$3.816 million higher than 2016 adjusted-recorded cost. The table below provides a breakdown of non-shared O&M costs.

CS-TSP Non-shared O&M	TY2019	Change from 2016
Research, Development & Demonstration (RD&D)	\$14,329,000	\$3,686,000
Policy & Environmental Solutions NSS	\$897,000	\$130,000
Total	\$15,226,000	\$3,816,000

22.6.1.1. Research, Development, & Demonstration

The RD&D program identifies and supports new technologies and research activities that benefit customers through improved reliability and safety, environmental benefits, and operational efficiencies.

Pursuant to Public Utilities Code section 740.1, RD&D activities are only authorized if achieving customer benefits is reasonably probable and the focus is not unnecessarily duplicative of efforts by other research organizations. To meet this standard, SoCalGas' RD&D program management teams routinely

²⁹⁸ D.16-06-054 at OP 12 at 332 requires SoCalGas to exclude costs for the Aliso Canyon leak from its TY2019 GRC application.

collaborate with other research funding sources such as the California Energy Commission (CEC).

The RD&D program supports projects in five main research domains: (a) Customer End-Use Applications which develop and commercialize technologies that improve efficiency, reduce environmental impacts of natural gas end-use applications, and support development and deployment of technologies that meet air emissions and efficiency goals; (b) Clean Generation which focuses on supporting the development of high-efficiency and low-emission distributed generation systems; (c) Clean Transportation which supports transportation infrastructure; (d) Gas Operations which develop technologies for public and employee safety, operational efficiencies, system reliability, and reduced environmental impacts; and (e) Low Carbon Resources which focus on technologies to improve biomethane production and use.

Costs were forecast using a zero-based methodology. SoCalGas also proposes to track costs in a one-way balancing account and excess costs shall be returned to ratepayers.

22.6.1.2. Policy & Environmental Solutions Non-Shared Services

The P&E NSS group monitors, analyzes, and determines how policy and legislative issues will affect SoCalGas' customer operations. The group also conducts analysis, strategy development, and implementation of local sustainability planning and other local and regional planning initiatives. A base year method was used to develop the forecast because costs are expected to remain at 2016 recorded levels.

22.6.2. Shared O&M

The forecast for CS-TSP shared O&M costs is \$4.008 million which is at the same level as 2016 recorded costs. There are two shared O&M cost categories as shown in the table below.

CS-TSP Shared O&M	2019	Change from 2016
Policy and Environmental Solutions SS	\$2,508,000	\$482,000
Business Strategy and Development	\$1,500,000	\$310,000
Total	\$4,008,000	\$792,000

22.6.2.1. Policy & Environmental Solutions Shared Services

The Policy & Environmental Solutions Shared Services (P&ES SS) group consists of Energy & Environmental Policy (E&EP), Environmental Affairs (EA), and the Planning & Legislative (P&LA) team. These groups are collectively responsible for policy analysis, engagement, outreach, and customer support related to existing and proposed state and federal policies, including laws and regulations related to natural gas and renewable gas utilization, environmental policy, air quality, and climate change policy.

The E&EP team supports the development and implementation of policies affecting natural gas and renewable gas delivery and utilization. The EA team is responsible for all regulatory proceedings originating from the nine local air districts in SoCalGas' service territory and for supporting customer compliance needs. Lastly, the P&LA team supports legislative and public policy matters.

SoCalGas' forecast includes funding for an additional 1.2 FTEs to respond to increased energy and environmental legislative, policy, and regulatory activities. SoCalGas utilized a five-year historical average to develop its forecast for E&EP and EA activities and a base year method for the P&LA team because this is a newly formed team.

22.6.2.2. Business Strategy and Development

The Business Strategy and Development organization is responsible for long-term planning, project analysis, and looking at natural gas industry trends. This group also provides analytical and other support for initiatives in maintaining system safety and integrity, enhancing system reliability, enabling diverse customer service capabilities and efficiencies, focusing on reasonable rates and continuous improvement, workforce investment, and leading clean energy solutions toward a decarbonized future. Costs were forecast using a five-year average.

22.6.3. Positions of Intervenors

ORA, Sierra Club and UCS provided comments on these costs.

ORA proposes using a five-year average for RD&D which results in an amount of \$9.886 million compared to SoCalGas' forecast of \$14.329 million.

Sierra Club and UCS recommend a decrease in SoCalGas' RD&D funding commensurate with increases to the CEC's Natural Gas R&D program fund. Sierra Club and UCS also recommend discontinuing SoCalGas' RD&D program.

Sierra Club and UCS recommend reductions for both non-shared and shared forecasts for Policy & Environmental Solutions but do not recommend a specific amount. Both parties add that the P&ES group has sought to block measures by state agencies and local governments to replace natural gas uses with electric options as a means of reducing reliance on fossil fuels. Sierra Club and UCS also state that SoCalGas should not recover costs for activities before state agencies and local government agencies related to the development of climate policy and GHG reduction measures.

22.6.4. Discussion

SoCalGas provided evidence that their RD&D programs complement other R&D programs such as solicitations, host sites, and co-funding projects that complement the CEC's Natural Gas R&D program as well as projects that supplement programs by the Environmental Protection Agency and Air Resource Board. SoCalGas also cites its power-to-gas project as research not addressed by other R&D programs. The above shows that SoCalGas' RD&D program is not duplicative of and actually supplements other R&D projects by government agencies and other groups. Thus, we do not find that this program should be discontinued.

ORA recommends using a five-year average but we find that a zero-based methodology is more forward-looking as it considers funding for projects that are being planned rather than projects that have already been completed. In addition, a zero-based method has been utilized for this cost center in SoCalGas' last two GRCs and we continue to find this method as more appropriate in this case. As for the recommendation by Sierra Club and UCS that funding be reduced commensurate with the CEC's Natural Gas R&D program fund, we find that the RD&D programs are not dependent on the CEC's funding level and may pursue projects that supplement R&D projects of other agencies and entities. Sierra Club and UCS also recommend a reduction to the RD&D funding but do not specify the level of reduction nor provide justification for this proposal.

Based on the above, we find that SoCalGas' request of \$14.329 million should be approved; as described below, this decision does not necessarily

approve the budget breakdown by sub-program SoCalGas has proposed.²⁹⁹ In addition, this authorized level of funding is subject to a one-way balancing account treatment such that any unspent funds are to be returned to ratepayers at the end of each GRC cycle.

Additionally, in order to increase transparency concerning SoCalGas' RD&D activities, allow proactive involvement by the CEC and other related organizations, and increased oversight and involvement by the Commission, we find that SoCalGas should host an annual workshop during the second quarter of 2020 and 2021 under supervision of the Commission's Energy Division. At these workshops, SoCalGas should present the result of the previous year's RD&D program and obtain input regarding its intended spending for the following calendar year.³⁰⁰ Prior to the workshop, SoCalGas should:

- Submit a report to Energy Division staff describing prior years' RD&D program. This should include a summary of ongoing and completed projects; funds expended, funding recipients, and leveraged funding; and an explanation of the process used for selecting RD&D project areas as well as the structure of SoCalGas' RD&D portfolio.
- Provide Energy Division staff with the workshop presentation materials as well as documentation of stakeholders consulted in the development of RD&D projects, both at least one week before the workshop.

²⁹⁹ SCG-21 Alexander Prepared Direct Testimony Table LLA-9 provides a funding forecast by RD&D sub-program area.

³⁰⁰ In this decision, the Commission has authorized a three-year GRC cycle including RD&D program funding for 2019-2021. The funding for the 2022 RD&D program presented in the 2021 workshop will be considered in SoCalGas' next GRC decision.

- Engage relevant stakeholders to encourage their attendance at the workshop, such as the California Energy Commission, Gas Technology Institute, the U.S. Department of Energy, and other organizations engaged in gas research and development.

SoCalGas should also present its budget broken down by research projects, request for proposals, and funding amounts. Other specific details concerning the workshops should be coordinated with the Commission's Energy Division staff. After considering stakeholder comments during the workshop, SoCalGas shall file a Tier 3 Advice Letter with its research plan for the following calendar year. The research plan should (1) detail budgets broken down by research sub-program area, (2) explain how the projects help improve reliability, safety, environmental benefits, or operational efficiencies and (3) discuss how SoCalGas incorporated feedback from workshop stakeholders and Commission staff. SoCalGas shall not record any RD&D project expenses in the one-way balancing account until the advice letter is approved. In addition, costs related to multi-year project and single-year projects under the current RD&D program will continue to be funded consistent with the TY2016 protocols until the planned completion of those projects.

Regarding Sierra Club's and UCS' objections to the funding for both non-shared and shared P&ES groups, we reviewed the various comment-letters sent by SoCalGas to state and local government agencies³⁰¹ that were identified by Sierra Club and UCS as constituting lobbying activities aimed at promoting natural gas use over electric options as a means of reducing fossil fuel reliance.

³⁰¹ Exhibit 139 Appendix A to E.

We reviewed each letter and find that each letter, as a whole, and when read in its entirety, does not constitute a means to block measures to replace natural gas with electric options. Instead, the comment-letters in question contain or provide SoCalGas' input and opinion with regards to the topics being addressed in the comment-letters. Some of the letters include information on the benefits of natural and renewable gas options or suggest consideration of these options but we find that these are generally informational as opposed to what Sierra Club and UCS suggest. To the extent that SoCalGas utilizes ratepayer funds on expenditures that go beyond providing information about natural gas and constitute inappropriate political activity,³⁰² the Commission will address such activities in the appropriate proceeding. Furthermore, the Commission reminds SoCalGas that any informational or educational material funded by ratepayers should not contravene the State's implementation of adopted legislation furthering programs to incentivize low emission buildings³⁰³ and increasing transportation electrification³⁰⁴ to achieve the state's climate goals.

³⁰² See allegations raised by Sierra Club and ORA in R.19-01-011, *Response of the Public Advocates Office to SoCalGas' Motion to Strike Sierra Club's Reply to Responses to Motion to Deny Party Status to C4BES*, filed July 5, 2019.

³⁰³ SB 1477 Section 1(b): "It is the intent of the Legislature to build on the success of the New Solar Homes Partnership Program by providing incentives to builders to design innovative, low-emission buildings, and to make low-emission heating equipment readily available and affordable in California."

³⁰⁴ SB 350 Section 32(I)(2): "It is the policy of the state and the intent of the Legislature to encourage transportation electrification as a means to achieve ambient air quality standards and the state's climate goals."

Parties do not oppose SoCalGas' forecast of \$1.50 million for Business Strategy and Development which we find to be reasonable and supported by the evidence presented.

Based on the above we find SoCalGas' TY2019 forecast for CS-TPS O&M costs of \$19.234 million reasonable and should be approved.

23. Supply Management & Logistics and Supplier Diversity

This section examines the forecast associated with the Supply Management & Logistics Department which is responsible for managing and purchasing procurement products and services needed to run the business with the aim of optimizing value of dollars spent. Efforts to reduce costs include vendor consolidation, direct re-negotiation, availing of early payment discounts, securing rebates, and leveraging spending.

This section only includes O&M costs which incorporate FOF-related benefits estimated at \$452,000 for SDG&E and \$373,000 for SoCalGas. Costs relating to the Aliso Canyon gas leak incident have been removed pursuant to D.16-06-054.

23.1. SoCalGas

23.1.1. Non-Shared Costs

The forecast methodology for all non-shared cost categories in this section was developed using a five-year historical average.

23.1.1.1. Procurement/Category Management

The TY2019 forecast for this group is \$2.859 million which is \$0.335 million above 2016 adjusted-recorded costs and includes FOF of \$4.059 million. The requested increase reflects continued technology investments planned for the TY. The group is composed of various managers, advisors, analysts, and team leads

that execute supply management strategies to reduce costs and collaborate with other departments to leverage new methods and technologies.

23.1.1.2. Inventory Management

The Inventory Management group forecasts, orders, receives, inventories, distributes, and accounts for tools, equipment, and materials needed by utility crews and contractors.³⁰⁵ The group also provides daily loading and unloading of materials and management of scrap metal and hazardous material. The requested amount for this group is \$13.342 million which is \$1.981 million over 2016 adjusted-recorded expenses. Cost drivers for the increase include material traceability which is a solution for tracking high pressure pipes, valves, fittings, and equipment. Costs also include warehousing storage space. Another cost driver is increased labor costs for meter shop activities previously reflected in the AMI balancing account.

23.1.1.3. Supplier Diversity

The forecast for Supplier Diversity is \$1.151 million which is \$0.464 million over 2016 adjusted-recorded expenses. The Supplier Diversity program is managed and implemented in accordance with General Order 156 which establishes guidelines for increasing procurement in all categories from women-owned, minority-owned, disabled veteran-owned, and LGBT-owned business enterprises. SoCalGas reduced its request by \$0.1 million or to \$1.051 million after identifying an adjustment during the course of discovery.

³⁰⁵ Exhibit 291 at DW-12.

23.1.1.4. Office Services

The forecast for the Office Services group is \$2.910 million for TY2019 which represents a \$0.424 million increase over 2016 adjusted-recorded expenses. Office Services operates and maintains three copy centers, distributes US mail, conducts courier services, and facilitates mass mailings. The group also manages the third-party provider that handles archives and records management, storage, and retention.

23.1.2. Shared Costs

The forecast methodology for shared costs is base year forecasting.

23.1.2.1. VP, Supply Management & Logistics

The forecast for this group is comprised of a VP, administrative support, and associated travel expenses, is \$0.334 million, which is around the same as base year levels or specifically, \$6,000 higher.

23.1.2.2. Policy & Integration

The request for the Policy & Integration team is \$0.186 million which is around the same as 2016 base year levels. This team conducts policy management, procedure development, audit response, data request collection, Sarbanes-Oxley testing, advisory services, and technology integration program management.

23.1.3. IT Business Unit Capital Projects

SoCalGas is requesting \$2.657 million in 2017 and \$2.547 million in 2018 for three IT-related capital projects. The projects consist of upgrades to the supply management and logistics reporting, interface portals, and increased e-procurement functionality.

23.1.4. Positions of Intervenors

ORA, NDC, CFC, and SBUA provided comments to this section.

ORA recommends \$12.559 million for Inventory Management which is \$0.783 million less than SoCalGas' request and \$2.486 million for Office Services which is \$0.424 million less than SoCalGas' request. ORA's recommended reduction for Inventory Management represent costs for additional FTEs associated with SoCalGas' proposal for a new Logistics Warehouse. For Office Services, ORA recommends using base year levels rather than a five-year average because costs have been decreasing from 2013 to 2016. ORA does not object to the forecasts for Procurement/Category Management, Supplier Diversity, and any of the shared services forecasts.

NDC recommends reducing the request for Supplier Diversity by \$0.421 million to \$0.730 million which is equivalent to base year level expenses. NDC later revised its request to \$970,800 after adjusting its calculation for returning employees that worked on Aliso Canyon gas leak incident.³⁰⁶ NDC argues that SoCalGas has been significantly under-spending its authorized budgets for Supplier Diversity in 2016 and 2017. Alternatively, NDC recommends directing SoCalGas to increase Supplier Diversity goals to match the funding requested.

CFC recommends reducing costs for Office Services by \$1.19 resulting in a total recommendation of \$1.72 million citing efficiencies in costs such as reduced printing costs.

SBUA recommends that the Commission direct SoCalGas to track and report on spending with non-diverse small businesses. This request is addressed in the SDG&E section.

³⁰⁶ NDC Opening Brief at 19.

23.1.5. Discussion

We reviewed the request for Procurement/Category Management and find that the evidence supports the request. We agree that a five-year historical average is an appropriate method for developing the TY2019 forecast and find the increase from previous levels to be reasonable and adequately explained. None of the other parties objected to this forecast and we find that the requested amount of \$2.859 million should be authorized.

For Inventory Management, ORA does not recommend any funding for the new Logistics Warehouse that SoCalGas plans to build and ORA's objection to \$0.783 million in O&M costs under the Inventory Management group represents labor costs for FTEs associated with the Logistics Warehouse. Our discussion regarding the Logistics Warehouse itself is in the next section of the decision under Fleet Services & SoCalGas Facilities Operations section. Because we are authorizing the request to build the Logistics Warehouse in that section, we are also authorizing the associated labor costs in this section. We therefore find the requested amount of \$13.342 million for Inventory Management should be approved. We find the request to be reasonable and supported by the evidence and agree with the forecast methodology that was utilized.

Regarding ORA's recommendation to use 2016 costs for Office Services, we agree with ORA that costs have been dropping each year from 2013 to 2016. However, the drop from \$2.876 million in 2015 to \$2.486 million in 2016 is a bit more severe than the drops from 2012 to 2015 which is around \$0.100 million each year. In addition, the requested funding of \$2.910 million for TY2019 is closer in actual dollar amount to expenses in 2012, 2013, 2014, and 2015 than it is

to 2016 as shown in Table 19-8 of Exhibit 414.³⁰⁷ Thus, we find that a five-year historical average better reflects projected costs for 2019. If costs in this GRC cycle continue to remain closer to 2016 levels, then the appropriate funding level can be reviewed in SoCalGas' next GRC filing. SoCalGas also presented sufficient evidence to describe the activities that will be supported by its request and the need for those activities. With respect to CFC's argument regarding reduced costs for mailing, we find SoCalGas' adequately addressed CFC's assertion by presenting that printing costs only represents a small fraction or 5 percent of costs and that mailing and courier expenses are anticipated to be higher because of a projected increase in fuel costs. We therefore find that the requested amount of \$2.910 million for Office Services should be approved.

Regarding Supplier Diversity, NDC states that SoCalGas spent 25 and 35 percent less than the authorized amounts in 2016 and 2017 respectively.³⁰⁸ In response, SoCalGas only states that they are proud of nearing parity between majority and diverse suppliers and did not directly address the under-spending raised by NDC except to add that the requested funding is needed to support planned activities and projects. In addition, NDC cited unusually high non-labor cost in 2012 to 2014 which skews the five-year average. Once again, SoCalGas did not directly address the issue raised by NDC. Based on the above, we agree with NDC that SoCalGas did not sufficiently justify the level of funding being requested for TY2019 considering that there are no changes presented with respect to Supplier Diversity goals. Therefore, we find NDC's recommended

³⁰⁷ Exhibit 414 at 7.

³⁰⁸ Exhibit 155, Response to NDC Data Request 010 Q03.

amount of \$970,800 to be more reasonable and should be adopted. With respect to NDC's alternate proposal, we find that this is not a feasible alternative given the information provided.

For the two shared services groups, we find use of base year forecasting to be appropriate as costs are relatively flat. We reviewed the evidence presented and find that the requests were appropriately explained and justified. ORA was the only party that reviewed SoCalGas' requests under these sections and ORA did not have any objections to the forecasts. Therefore, we find that the requested amounts of \$0.334 million for VP, Supply Management & Logistics and \$0.186 million for Policy & Logistics should be approved.

To summarize, all of SoCalGas' O&M forecasts under this section should be approved except for the request for Supplier Diversity which is being adjusted following NDC's recommended amount. We also reviewed the request for the three IT projects and find the request reasonable and should be approved. No party objected to these proposed projects.

23.2. SDG&E

23.2.1. Non-Shared Costs

The non-shared cost categories are the same as those described in the SoCalGas section with the only difference being the amounts requested which are listed below. All the forecasts were also derived using a five-year historical average.

Procurement/Category Management: \$1.568 million. This amount includes FOF of \$0.897 million.

Inventory Management: \$5.039 million

Supplier Diversity: \$1.142 million. SDG&E reduced its request by \$0.1 million or to \$1.042 million after identifying an adjustment during the course of discovery.

Office Services: \$2.229 million

23.2.2. Shared Costs

The shared costs under this section contain the shared services forecasts for the Procurement/Category group, Policy & Integration, and Office Services. The functions and forecast methodologies of these groups were described in the SoCalGas section. The shared costs for Procurement/Category Management and Office Services listed below are separate and distinct from the non-shared costs requested by SoCalGas and SDG&E in sections 23.1.1 and 23.2.1 respectively.

Procurement/Category Management: \$2.668 million

Policy & Integration: \$0.720 million

Office Services: \$1.300 million

23.2.3. Positions of Intervenors

ORA does not oppose SDG&E's shared and non-shared forecasts based on its analysis.

NDC recommends reducing the request for Supplier Diversity by \$0.228 million to \$0.854 million which is equivalent to base year level expenses for similar reasons provided in the SoCalGas section. NDC makes a similar alternative request as discussed in the SoCalGas section for SDG&E to be directed to increase its Supplier Diversity goals as an alternative.

SBUA recommends that the Commission direct SDG&E to track and report spending on non-diverse small businesses. SBUA also recommends \$4.800 or a reduction of \$0.229 million for Inventory Management because of the installation of smart meters. For Shared Services costs, SBUA recommends a reduction of

\$0.788 million for Procurement/Category Management because the goals of Category Management are to advocate for vendor consolidation which is contrary to what SBUA promotes and \$0.250 million for Policy & Integration because this group is partially responsible for implementing policies that exclude small businesses.

23.2.4. Discussion

ORA, NDC, CFC, and SBUA did not have any objections to the non-shared portion of Procurement/Category Management and both the shared and non-shared portions of Office Services. We reviewed the testimonies submitted by SDG&E for these sections and find the requests to be reasonable and adequately supported by the testimonies presented. We also agree with the forecast methodologies applied in deriving the forecasts which is five-year historical average for the non-shared costs and base year forecasting for the non-shared costs. The five-year average captures fluctuations during the five-year period and the base year method was appropriate for when costs are relatively flat. We therefore find that the requested amounts of \$1.568 million for the non-shared services portion of Procurement/Category Management, and the forecasts of \$2.229 and \$1.300 million for the respective non-shared and shared portions of Office Services should be authorized.

NDC raises the same issues concerning Supplier Diversity as it did in the SoCalGas portion and we make the same findings and conclusions that we did in the SoCalGas portion of this section which we discussed in section 23.1.4. NDC also cited an additional flaw to SDG&E's calculation, which included unusually high labor costs in 2014 because of costs associated with two FTEs to handle additional work that is no longer being performed in 2015. We find that NDC's recommended amount of \$0.854 million should be adopted.

For SBUA's recommendation to direct Applicants to track and report spending on non-diverse small businesses, we find this to be outside the scope of the GRC. Currently, GO 156 only requires the tracking of spending on diverse businesses and this GRC is not the proper forum to consider proposed revisions to GO 156. With respect to SBUA's recommended reduction to Inventory Management due to the installation of smart meters, we find that the proposed reductions lack support and do not have sufficient basis. We also agree with SDG&E that the proposed increases reflect additional costs for material traceability and are not connected with the installation of smart meters. As for the recommended reductions to Procurement/Category Management, and Policy & Integration, we also find that the requests lack sufficient basis. SBUA did not establish that SDG&E has a policy of excluding small businesses and did not explain the basis for the amounts it recommends as reductions. For its part, we find that SDG&E provided sufficient basis to justify the amounts requested for these cost categories. The various cost drivers and reasons for moderate increases requested were supported by evidence. We also agree with the forecast methodologies that were utilized.

To summarize, all of SDG&E's requested forecasts for this section should be authorized except for Supplier Diversity which should be reduced following NDC's primary recommendation.

24. Fleet Services and SoCalGas Facility Operations

This section reviews Applicants' Fleet Services costs and SoCalGas' Facility Operations.

Fleet Services acquires, maintains, repairs, and salvages vehicles and related equipment to support the provision of services to customers. Fleet Services is comprised of a mix of vehicles which are classified as:

(a) over-the-road (OTR) vehicles such as automobiles and light, medium, and heavy trucks; and (b) non-OTR vehicles such as power operated equipment, trailers, and forklifts. Fleet Services provides daily operational support to various other organizations within SDG&E and SoCalGas.

This section also addresses SoCalGas' Facility Operations.³⁰⁹ Facility Operations encompasses 80 staffed locations including general offices, bases, multi-use sites, branch offices, and telecommunications sites.³¹⁰ Facility Operations is also responsible for providing a safe, compliant, reliable, and suitable working environment for SoCalGas' employees. Key activities also include proper training of facility maintenance personnel to comply with applicable rules and regulations.

24.1. SoCalGas

The total forecast for non-shared costs is \$90.751 million³¹¹ and \$6.345 million for shared services. Savings of \$2.050 million as a result of FOF are incorporated in the O&M forecasts. Pursuant to D.16-06-054, costs totaling \$32,000 related to the Aliso incident from Fleet Services and Facility Operations are excluded from the forecasts and from historical information. Meanwhile, the forecasts for capital are \$42.416 million for 2017, \$73.569 million for 2018, and \$82.372 million for 2019. In addition, SoCalGas is requesting \$0.502 million in 2017, \$2.387 million in 2018, and \$7.601 million in 2019 for IT-related capital

³⁰⁹ SDG&E's Facilities Operations is included in the next section under Real estate and SDG&E Land services and Facilities.

³¹⁰ Exhibit 188 at CLH-4.

³¹¹ Revised from \$90.751 million to \$90.086 million in the Update Testimony (Exhibit 514) at Attachment H.

projects. These IT projects will be discussed separate from the non-IT capital projects.

As is the case with other sections of the decision, certain costs included in this section are RAMP-related costs supporting activities that mitigate key risks identified in the RAMP Report. Key risks being mitigated are: (a) Employee, Contractor, Customer, and Public Safety; (b) Workplace Violence; and (c) Physical Security of Critical Gas Infrastructure. Total RAMP costs are \$1.232 million for O&M and \$0.600 million for capital with the entire amount being associated with incremental activities resulting from the RAMP process. Activities included relate to public and employee safety, system reliability, regulatory and legislative compliance, and pipeline system integrity. Three emergency command vehicle centers are also included in the RAMP requests. Other activities include adding security systems and contract security, and planning, awareness, and incident management.

24.1.1. Non-Shared O&M Costs

As stated above, the TY2019 forecast for non-shared costs is \$90.751 million which is \$33.627 million higher than 2016 adjusted, recorded expenses. Non-shared costs include Ownership Costs, Maintenance Operations, Fleet Management, and Facility Operations.

24.1.1.1. Ownership Costs

SoCalGas' fleet consists of over 5,400 vehicles and power-operated equipment. Table CLH-9 of Exhibit 188 provides a list of vehicle and equipment types and the total for each class. According to SoCalGas, it lease-finances its vehicles and incurs annual repayment of principal and interest for each vehicle

over the lease term with replacement of each being based on the targeted useful life for each class of vehicles.³¹² The table below provides the TY2019 forecasts for Ownership Costs as well as the difference from 2016 adjusted, recorded expenses. Costs were forecast primarily using a cash flow analysis.

Ownership	TY2019 Forecast	Change from 2016 costs
Amortization	\$35,175,000	\$17,414,000
Interest	\$5,956,000	\$4,352,000
Salvage	(\$1,754,000)	(\$941,000)
License Fees & Sales Tax	\$6,184,000	\$4,394,000
Total	\$45,561,000	\$25,219,000

Amortization

The annual repayment of principal for the fleet leases and is composed of active leases and new leases for replacements and additional vehicles. As stated above, replacement scheduling is based on the targeted useful life of the vehicle. Aside from traditional costs, SoCalGas is supporting California initiatives to reduce petroleum use and GHG emission by increasing its fleet of natural gas powered vehicles and replacing its diesel and petroleum vehicles. New Airborne Toxic Control Measures (ATCM) also require the replacement of heavy duty diesel vehicles.

Interest

All replacement and incremental vehicles are to be financed under lease arrangements with floating interest rates.

Salvage

Vehicles are sold for salvage at the end of their useful life.

³¹² Exhibit 188 at CLH-18.

License Fees & Sales Tax

License fees are generally fees that are paid to the state of California each year.

24.1.1.2. Maintenance Operations

The table below provides the TY2019 forecasts for Maintenance Operations as well as the difference from 2016 adjusted, recorded expenses. Costs were forecast using a five-year historical average.

Maintenance Operations	TY2019 Forecast	Change from 2016 costs
Maintenance Operations	\$13,342,000	\$1,928,000
Automotive Fuels	\$12,503,000	\$2,807,000
Total	\$25,845,000	\$4,735,000

Maintenance Operations – performs vehicle safety inspections and other routine maintenance including the replacement of worn, defective parts, and damaged parts. Costs include technician training.

Automotive Fuels – fuel costs are based on price and quantity consumed.

24.1.1.3. Fleet Management

Fleet Management consists of costs for the Fleet Services management staff. The TY2019 forecast is \$1.100 million which is \$0.598 million higher than 2016 costs. The forecast was developed using a five-year average.

24.1.1.4. Facility Operations

The forecast for Facility Operations is \$18.245 million³¹³ which is \$3.075 million higher than 2016 adjusted, recorded costs. Costs were forecast using a five-year historical average. Facility Operations provides O&M support

³¹³ Revised from \$18.245 million to \$17.580 million in the Update Testimony (Exhibit 514) at Attachment H.

to 80 owned staffed utility facilities comprised of 64 operating bases, 6 owned branch offices, 6 multi-use facilities, and 4 regional headquarters. In addition, O&M support is also provided to 37 leased telecommunications facilities and 37 leased branch offices.

24.1.2. Shared O&M Costs

The TY2019 forecast for Shared O&M Costs is \$6.345 million which is \$0.609 million higher than 2016 costs. Shared services activities are comprised of Shared Fleet Management and Shared Facility Operations.

The forecast for Shared Fleet Management is \$2.500 million using a three-year average. A three-year average was used to more accurately reflect recent staffing levels. On the other hand, the forecast for Shared Facility Operations is \$3.845 million using a four-year average. Most of the Shared Facility Operations costs reflect costs associated with the Monterey Park facility and the Gas Company Tower. A four-year average was utilized because the new employee learning center in Monterey Park was completed in 2013 and according to SoCalGas, the four-year average better reflects projected costs for the TY.

24.1.3. Position of Intervenors

ORA, TURN, Sierra Club, and UCS provided comments to this section and their recommendations are as follows:

Ownership Costs

ORA recommends using 2017 actual recorded ownership costs which is \$23.319 million. ORA states that SoCalGas' forecast which is based on vehicle additions by year results in overcollections and is not justified based on historic data. TURN agrees with ORA's recommendation and proposes the same amount. Alternatively, TURN proposes \$27.080 million which add costs for

replacement of vehicles to comply with ATCM requirements. Sierra Club and UCS state that SoCalGas should not be allowed to recover costs for NGVs where electric or hybrid vehicles are available for the same vehicle class.

SoCalGas argues that the proposals by ORA and TURN do not account for current leases, mandated replacements, greening of the fleet through the purchase of AFVs, incremental vehicles to meet business needs, increased fees for vehicle registrations, and vehicles replacements on order or scheduled to be replaced. SoCalGas included a table showing these needs in Table CLH-3 of Exhibit 192.

Maintenance Operations

ORA recommends using a three-year average given that expenses are trending downward. ORA also objects to the adjustments for backfilling of personnel lost due to retirement and for non-labor maintenance costs. TURN raised additional arguments in support of ORA's recommended amounts. TURN also adds that costs during the last three years are significantly lower than costs in 2012 and 2013.

Fleet Management

ORA agrees with the five-year average used to develop the forecast but disagrees with an adjustment to backfill three FTEs and add a new position.

Facility Operations

ORA agrees with use of the five-year average but disagrees with the adjustments to the five-year average relating to NGV refueling stations and for a real estate planning study. TURN recommends using a three-year average.

Shared O&M Costs

Parties do not object to SoCalGas' Shared O&M forecast.

24.1.4. Discussion

Ownership Costs

In this instance, we find it useful to include 2017 recorded data in our analysis as it supplements historical data and helps present a clearer picture of historical costs. As shown in Table 19-10 of Exhibit 414,³¹⁴ Ownership Costs from 2012 to 2017 ranged from \$16.503 million to \$23.319 million and year-to-year increases has not exceeded \$3.00 million. For its TY2019 forecast however, SoCalGas' request is \$25.219 million more than 2016 costs or \$22.242 million more if we were to compare it with 2017 data.

In our review of SoCalGas' testimony, we find that SoCalGas did not fully explain why costs were forecast to increase by such an amount compared to other years except for stating that some of the costs are to comply with state and federal requirements. Yet Table CLH-3 in Exhibit 192³¹⁵ shows that increased compliance requirements only accounts for around \$5.650 million of the increase.

With respect to ordered and planned vehicle replacements, we find that these cost drivers are not unique to the TY. In 2017 for example, there presumably were orders and planned replacements from prior years that took effect in 2017 and these costs already are reflected in 2017 actual expenses.

With respect to SoCalGas' plans to increase its AFV fleet pursuant to state goals to reduce GHG emissions, we support SoCalGas' goal of reducing GHG emissions. We also agree with Sierra club that UCS,³¹⁶ however, that California's express policy is to meet this goal through widespread transportation

³¹⁴ Exhibit 414 at 10.

³¹⁵ Exhibit 192 at CLH-7.

³¹⁶ See Sierra Club and UCS Opening Brief at 3.

electrification.³¹⁷ Even if natural gas vehicles offer any reduction in GHG emissions vis-à-vis petroleum and diesel-fuel vehicles,³¹⁸ whatever benefit they offer do not justify the cost presented here. We therefore deny the request. If SoCalGas pursues these investments in later years, such as SoCalGas' next GRC, it should be prepared to sincerely explore what portions of its fleet could transition to either battery electric or hybrid electric vehicles. Finally, for costs of vehicles that SoCalGas suggests are the result of incremental business needs, we find that these needs have not been sufficiently justified especially in light of the historical costs presented in Table 19-10 of Exhibit 414.

Based on all the above, we find ORA's recommendation to use 2017 actual vehicle ownership costs more appropriate. However, we agree with TURN's alternate proposal to add costs relating to ATCM compliance replacements which total \$3.034 million. We also find it appropriate to authorize \$0.400 million representing increased license fees. This results in a total of \$26.753 million that should be authorized for this cost category.

Maintenance Operations

We reviewed the testimony submitted by parties and arguments raised in briefs. Based on our review, we find that a five-year average better captures the highs and lows of historical costs as opposed to a three-year average since there are more years of data that are included and considered. Recorded costs during 2014 to 2016 ranged from over \$21 to \$23 million while costs in 2012 and 2013 were \$26.087 million and \$25.010 million respectively. We find that the

³¹⁷ See Pub. Util. Code § 740.12; and D.18-05-040, *Transportation Electrification Standard Review Projects* (June 5, 2018).

³¹⁸ See Sierra club and UCS Opening Brief at 32 to 33.

difference is not significant enough to indicate that there was a drastic change in costs. Parties also did not cite to any change in operations or other reasons that would lead us to conclude that there has been a permanent shift in costs.

Regarding ORA's objections to the incremental adjustments made by SoCalGas, we note that there were four adjustments: \$0.863 million for backfilling or personnel; \$0.284 million associated with incremental vehicles; \$0.244 million for training and certification; and a reduction of (\$0.245 million) for FOF. For the additional personnel, SoCalGas states that around 15 FTEs have been lost due to retirements and transfers from 2012 to 2016. We note however that SoCalGas has been operating with less FTEs post-2012 which seems to indicate that backfilling all the positions that had become vacant is not necessary. SoCalGas proposes to fill all 15 FTEs that had become vacant since 2012 which would bring the FTE total to 91.5 from 76.6 in 2016. SoCalGas cited several reasons such as conducting smog inspections and compliance with an inspection program by the California Highway Patrol (CHP) that now requires more frequent inspections. However, the revised CHP program became effective in 2016 and smog inspections are not new so we find that SoCalGas has been able to comply with these programs with the FTE level that it has. Based on the above, we find it reasonable to approve 50 percent of the requested adjustment to backfill vacant FTEs as this level of funding will enable SoCalGas to perform the increased work it has identified but takes into account the number of FTEs during recent years.

We have no objections to the adjustment for FOF and training and certification. However, for incremental non-labor maintenance costs associated with incremental vehicles, because we are disapproving most of the funds

requested for incremental vehicles in our discussion on Ownership Costs, we find it reasonable and appropriate to deny the incremental maintenance costs.

To summarize, we find that SoCalGas' forecast costs for Maintenance Operations should be adjusted by removing the \$0.284 million for incremental maintenance costs and \$0.431 million from backfilling of personnel resulting in \$12.627 million that should be approved.

For Automotive Fuels, we find that a five-year average is more appropriate as a longer period better captures fluctuations in fuel costs. ORA objected to the \$0.709 million adjustment associated with incremental vehicles. Because we are rejecting most of the requested costs for incremental vehicles under ownership costs, we find ORA's recommendation to be reasonable and deduct \$0.709 million from SoCalGas' forecast resulting in \$11.794 million that should be authorized.

Combining the two totals results in \$24.421 million that should be approved for Maintenance Operations which includes Maintenance Operations and Automotive Fuels.

Fleet Management

We agree with SoCalGas and ORA that use of the five-year historical average to develop the TY2019 forecast is appropriate. With regards to the backfilling of three FTEs, SoCalGas explains that there has been a reduction of FTEs over time due to retirement. However, we agree with ORA that SoCalGas does not adequately explain why the FTE total is forecast to go up from 7.4 in 2016 to 14.8 in TY2019. Table 19-15 of Exhibit 414³¹⁹ shows the number of FTEs

³¹⁹ Exhibit 414 at 16.

from 2012 to 2016 ranged from 7.4 to 11.9. Based on the historical data, we find it reasonable to only authorize two of the four FTEs that are being added incrementally. This would put the total FTE for TY2019 at 12.6 which is still higher than the FTE count from 2012 to 2016. Therefore, for Fleet Management, we find that SoCalGas' request should be reduced to \$0.895 million. The reduction of \$0.205 million corresponds to the two FTEs that are not approved.

Facility Operations

In the TY2016 GRC, a three-year average was utilized to exclude 2009 which was an atypical year due to the recession. However, we find that use of a longer period better captures year-to-year fluctuations in actual costs and so we find that use of a five-year average is appropriate for this GRC. SoCalGas made four adjustments to arrive at the TY2019 forecast: \$1.574 million for items related to NGV refueling stations; \$1.047 million for RAMP security; \$1.00 million for a real estate planning study; and a reduction of (\$1.739 million) for FOF.

We agree with the adjustments to FOF and the additional security. For costs relating to the real estate planning study, SoCalGas agrees that this is a non-recurring cost and so we find that only 1/3 of the requested amount of \$0.333 million should be authorized to reflect only one-year of costs in the three-year GRC period.³²⁰

For the line item relating to NGV refueling stations, SoCalGas explains that the costs pertaining to NGV refueling stations is \$0.500 million of the \$1.574 million with the remainder of the amount covering costs for increased

³²⁰ SoCalGas reduced the forecast by \$0.667 million in Update Testimony (Exhibit 514) at Attachment H.

contracted services, lighting upgrades, and costs for electrical panels, doors, and preventive maintenance. Because we are reducing SoCalGas' capital request for NGV refueling stations (Section 24.1.3.6) in the capital portion of this section by approximately 60 percent, we agree with ORA's recommendation to likewise reduce the O&M amount pertaining to NGV refueling stations by the same percentage. This results in a reduction of \$0.300 million. Based on the above discussion, we find that SoCalGas' requested amount for Facility Operations should be adjusted to \$17.280 million.

Shared O&M Costs

Parties do not object to SoCalGas' Shared O&M forecasts and based on our review, we find the forecast amounts to be reasonable and supported by the evidence. We also have no objections to the forecast methodologies that were utilized as the three-year average utilized for Shared Fleet Management and the four-year average utilized for Shared Facility Operations adequately reflect projected costs for 2019. The total forecast is also not far removed from total costs in 2016. Thus, we find that SoCalGas' request of \$6.345 million for Shared O&M Costs is reasonable and should be approved.

24.1.4.1. Summary

Based on the discussions above, the following costs are authorized for Non-Shared O&M costs:

Ownership Costs: \$26.753 million

Maintenance Operations: \$24.421 million

Fleet Management: \$0.895 million

Facility Operations: \$17.280 million

Shared O&M: \$6.345 million

24.1.5. Capital

SoCalGas' forecasts for capital expenses are \$42.416 million in 2017, \$73.569 million in 2018, and \$82.372 million in 2019. The table below provides a breakdown of the requested capital costs. Because there are various proposals with regards to each project, our findings will be listed as each topic is discussed instead of being combined at the end.

Capital	2017	2018	2019
Infrastructure & Improvements	\$24,243,000	\$45,863,000	\$59,923,000
Safety & Environmental	\$2,450,000	\$2,075,000	\$2,000,000
Bakersfield Multi-Use Facility	\$7,000,000	\$7,000,000	\$0
Facility Energy Management Systems	\$1,000,000	\$500,000	\$0
Fleet Projects	\$548,000	\$2,194,000	\$1,650,000
NGV Refueling Stations	\$7,175,000	\$15,937,000	\$18,799,000
Total	\$42,416,000	\$73,569,000	\$82,372,000

24.1.5.1. Infrastructure & Improvements (Capital)

The forecast for Infrastructure & Improvements will support SoCalGas' facility operations by providing repair, improvements, and upgrades to various facilities and equipment in order to adequately support business operations. A more detailed breakdown of costs is provided in the table below and includes other cost centers that are under Infrastructure & Improvements. The general types of additions, improvements, and upgrades are described Exhibit 188 at CLH-43 to 44. Costs for Infrastructure & Improvements were forecast using the current aggregate value of owned buildings and applying a capital renewal rate based on an industry benchmarking system.

Infrastructure & Improvements	2017	2018	2019
Infrastructure & Improvements	\$18,914,000	\$20,649,000	\$18,935,000
Facility Renovations	\$3,880,000	\$21,514,000	\$37,138,000
Sustainability Projects	\$1,449,000	\$3,100,000	\$3,250,000
Physical Security Infrastructure Enhancements (RAMP)	\$0	\$600,000	\$600,000
Total	\$24,243,000	\$45,863,000	\$59,923,000

Infrastructure & Improvements

For repair, improvements and additions to various facilities.

Facility Renovations

For aging facilities that no longer meet workforce space requirements and to improve the functionality of buildings and sites. Costs were forecast using a zero-based methodology because of lack of historical data.

Sustainability Projects

Includes solar systems at facilities to generate renewable energy and xeriscaping³²¹ to improve water conservation. Costs were forecast using a zero-based methodology because of lack of historical data.

Physical Security Infrastructure Enhancements

Includes additional security cameras, enhanced perimeter fencing, and controlled access points at various facilities. Costs were forecast using a zero-based methodology because of lack of historical data.

ORA recommends using 2017 recorded data but does not object to the 2018 and 2019 proposals by SoCalGas for Infrastructure & Improvements, Sustainability Projects, and Physical Security Infrastructure Enhancements.

³²¹ Xeriscaping is the process of landscaping or gardening that reduces or eliminate the need for supplemental water from irrigation.

For Facility Renovations, ORA states that funds were requested in SoCalGas' prior GRC to conduct facility improvements for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities but SoCalGas redirected funding to focus on accelerating the greening of its fleet through the construction and renovation of its NGV refueling stations.³²² ORA adds that SoCalGas is requesting the same level of funding for the same facilities that it had requested funds for in the prior GRC. ORA also argues that expenditures for capital renovations are not a priority and that projects involving the facilities to be renovated still do not have specific start dates after four years of planning. Thus, ORA recommends \$0 funding in 2017 for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities and half the funding for 2018 and 2019.

ORA also recommends \$0 funding for the Gas Control Facility, Logistics Warehouse, and Collaborative Training Facility under Facility Renovations.

TURN recommends \$0 funding for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities or as an alternative, supports ORA's recommendation of \$0 funding for 2017 and half of SoCalGas' requested funding for 2018 and 2019.

Regarding ORA's recommendation to use 2017 recorded data for Infrastructure & Improvements, Sustainability Projects, and Physical Security Infrastructure Enhancements, consistent with the decision's approach to similar recommendations, we find that updating only select data from 2016 to 2017 recorded costs will result in inconsistency as not all data is updated. It is also not feasible to update all data as there are vast amounts of data included in the

³²² Exhibit 414 at 21.

application. While we recognize that there are instances and circumstances where it is prudent, necessary, and reasonable to apply additional and updated data in select areas regardless of the resulting inconsistency, we find that this is not such a case. Therefore, we find that SoCalGas' forecast amounts for Infrastructure & Improvements, Sustainability Projects, and Physical Security Infrastructure Enhancements should be authorized.

With respect to the objections regarding facility improvements for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities, the main objection is that funds had already been authorized in SoCalGas' prior GRC except that the funds were utilized for other projects. We recognize that there are instances where funds authorized for certain projects are diverted to higher priority projects. In this case, it is clear where the funds went and so the funds that were authorized are more or less accounted for and were not spent frivolously. ORA's objection is not that the previously authorized funds were diverted but that the proposed facility improvements might not be necessary at this time. However, SoCalGas argues that the facility improvements are necessary and considered priority. SoCalGas also provided updated details regarding the proposed upgrades. Based on the above, we find the requested costs for 2018 and 2019 reasonable and necessary. For 2017, since no amounts were actually spent, we find it reasonable to deny requested amounts for 2017.

With regards to the Gas Control facility, ORA's recommendation is based on the project not being completed by 2019. However, SoCalGas states that it has accelerated timing for the project and provided details such as the site for the project and that it has hired a project manager and architect in late 2017. Based on these developments, we find that costs for the project should not be disallowed because of its necessity which ORA does not dispute. For the

Logistics Warehouse, SoCalGas explains that it is needed for material traceability in order to improve inventory management and keep up with new regulations.³²³ SoCalGas adds that material traceability is also a solution for tracking high pressure pipes, and valve fittings and ensures that traceable, verifiable, and complete records are readily available. Regarding denial of costs for the Collaborative Training Facility, ORA did not provide sufficient basis for its recommended disallowance whereas SoCalGas provided testimony regarding its necessity. Based on the above, we find that ORA's recommended disallowance of costs for the Gas Control Facility, Logistics Warehouse, and Collaborative Training Facility should be denied.

To summarize, for Infrastructure & Improvements, SoCalGas' requested amounts of \$24.243 million for 2017 should be adjusted by removing 2017 costs of \$3.880 million for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities. SoCalGas' forecasts of \$45.863 million for 2018 and \$59.923 million for 2019 should be approved.

24.1.5.2. Safety & Environmental

Costs under Safety & Environmental are to comply with American Disabilities Act improvements at the San Luis Obispo and Santa Barbara facilities which will improve customer access. Costs were forecast using a zero-based methodology.

ORA recommends using 2017 actual costs but accepts SoCalGas' 2018 and 2019 forecasts.

³²³ Exhibit 222 at JC/SF-5.

We reviewed SoCalGas' forecast and find it to be reasonable and supported by the evidence. With regards to ORA's recommendation, we find that updating data to 2017 actual costs in select instances only may lead to inconsistencies as not all data is being updated. Thus, for this instance, we find it more reasonable to rely on the 2017 forecast. Based on the above, we find SoCalGas' requested amounts of \$2.450 million for 2017, \$2.075 million for 2018, and \$2.000 million for 2019 for Safety & Environmental should be authorized.

24.1.5.3. Bakersfield Multi-Use Facility

Costs are for construction of a new multi-use facility driven by continuous customer expansion which necessitates a larger facility that the current facility cannot accommodate. Costs were forecast using a zero-based methodology.

ORA accepts the total cost for the project but recommends moving most of the project to 2018 and 2019, instead of 2017 and 2018 as proposed by SoCalGas.

We reviewed SoCalGas' proposal to create a new multi-use facility in Bakersfield and find the request and proposed costs to be reasonable. ORA recommended moving back the project by one year but SoCalGas provided renovation plans, facility studies, and an updated timeline for the project³²⁴ to show that the in-service date is expected around February 2019 and not December 2019 as ORA suggested. SoCalGas adds that groundbreaking for the facility had already taken place as of April 2018. Based on the above, we find that the proposed completion date remains as is and that the forecasts of \$7.00 million each for 2017 and 2018 should be approved.

³²⁴ Exhibit 192, Appendix A.

24.1.5.4. Facility Energy Management Systems

Requested costs are to install new systems and to upgrade existing systems which will improve energy management and lighting of heating, ventilation, and air conditioning. The forecast was developed using a zero-based methodology.

ORA recommends zero for 2017 as there were no actual expenditures for the project but accepts the 2018 forecast. SoCalGas did not object to ORA's recommendation. In this instance, we find it reasonable to rely on the updated 2017 data which shows that no funds were expended pursuant to the project. We therefore find it reasonable to adopt ORA's recommendation and authorize \$0 for 2017 and \$0.500 million for 2018.

24.1.5.5. Fleet Projects

Costs for Fleet Projects are to replace capital tools and equipment, to construct a new training facility, and to replace underground storage tanks in a systematic way. Costs were forecast using a zero-based methodology.

ORA recommends using 2017 costs but accepts SoCalGas' 2018 and 2019 forecasts.

We reviewed SoCalGas' forecast and find it to be reasonable and supported by the evidence. With regards to ORA's recommendation, we find that updating data to 2017 actual costs in select instances only may lead to inconsistencies as not all data is being updated. Thus, for this instance, we find it more reasonable to rely on the 2017 forecast. Based on the above, we find SoCalGas' requested amounts of \$0.548 million for 2017, \$2.194 million for 2018, and \$1.650 million for 2019 for Fleet Projects should be authorized.

24.1.5.6. Natural Gas Vehicle Refueling Stations

The NGV Refueling Stations will support SoCalGas' drive to convert a majority its fleet to Alternative Fuel Vehicles (AFV) with a target of over

1,300 AFVs by 2020. SoCalGas currently owns 27 NGV refueling stations and the requested costs will fund the addition of eight NGV refueling stations and provide replacement and upgrades to improve capabilities, refueling capacity, and replacement of aging equipment. Costs were forecast using a zero-based methodology.

ORA recommends using actual 2017 expenditures and recommends using 2017 costs as the funding level for 2018 and also for 2019. TURN supports ORA's recommendation. Sierra Club and UCS disagree with additional investment for NGV refueling stations and suggest that costs for electric infrastructure to support electric and hybrid vehicles are much more efficient.

We find that SoCalGas' request for NGV Refueling Stations reflects the projected number of vehicles based on the amount requested for Ownership Costs. In light of the disapproval of a significant portion of SoCalGas' requested amounts under Ownership Costs, we find it reasonable to also reduce the amounts requested here and find ORA's recommendation to use 2017 actual costs for 2017, 2018, and 2019. It is our expectation that these amounts will be used for replacements and upgrades of existing facilities as opposed to the addition of new NGV refueling stations. Based on the above, we find it reasonable to approve \$7.542 million each for 2017, 2018, and 2019.

24.1.6. IT Business Unit Capital Projects

As stated previously, SoCalGas is requesting \$0.502 million in 2017, \$2.387 million in 2018, and \$7.601 million in 2019 for IT-related capital projects. The request is for four capital projects and specific details regarding these

projects are provided in Exhibit 302.³²⁵ We reviewed all projects and find the Fleet System Upgrade Phase I and Fleet Fuel Management projects to be reasonable and necessary as these projects provide upgrades and replacements to the current system which is now obsolete and no longer supported by the vendor.

However, we find it reasonable to deny the funding requests for the Facility Optimization & System Upgrade project and the Fleet System Upgrade Phase III. The testimony supporting these two projects explains the proposed upgrades and the areas that are intended to be approved but do not explain how existing systems are inadequate.

Removing the funding requested for the two projects that are being denied results in \$0.502 million for 2017, \$0 for 2018, and \$5.482 million for 2019 that should be approved.

24.2. SDG&E

SDG&E's TY2019 O&M forecast for Fleet Services is \$45.456 million which is \$17.513 million higher than 2016 adjusted, recorded costs. Savings of approximately \$12,000 are incorporated in the forecast. SDG&E is also requesting \$2.168 million in 2017, \$4.514 million in 2018, and \$7.632 million in 2019 for IT-related projects.

24.2.1. Non-Shared Costs

The TY2019 forecast for non-shared costs is \$43.839 million which is \$17.252 million higher than 2016 adjusted, recorded expenses. Non-shared costs include Ownership Costs, Maintenance Operations, and Fleet Management. The

³²⁵ Exhibit 302 at 285 to 309.

descriptions, cost drivers, and forecast methodology for each of these cost categories correspond to those in the SoCalGas section as can be found in sections 24.1.1.1., 24.1.1.2, and 24.1.1.3 of the decision.

24.2.1.1. Ownership Costs

SDG&E's fleet consists of 2,134 vehicles and power-operated equipment. Table CLH-5 of Exhibit 188 provides a list of vehicle and equipment types and the total for each class. The table below provides the TY2019 forecasts for Ownership Costs as well as the difference from 2016 adjusted, recorded expenses. All costs were forecast using a zero-based methodology.

Ownership	TY2019 Forecast	Change from 2016 costs
Amortization	\$18,632,000	\$10,295,000
Interest	\$3,480,000	\$2,642,000
Salvage	(\$1,166,000)	(\$882,000)
License Fees & Sales Tax	\$3,543,000	\$2,318,000
Total	\$24,489,000	\$14,373,000

24.2.1.2. Maintenance Operations

The table below provides the TY2019 forecasts for Maintenance Operations as well as the difference from 2016 adjusted, recorded expenses.

Maintenance Operations	TY2019 Forecast	Change from 2016 costs
Maintenance Operations	\$12,062,000	\$1,063,000
Automotive Fuels	\$6,740,000	\$1,992,000
Total	\$18,802,000	\$3,055,000

24.2.1.3. Fleet Management

SDG&E's TY2019 forecast for Fleet Management is \$0.548 million which is \$0.176 million less than 2016 costs.

24.2.2. Shared O&M Costs

SDG&E's TY2019 forecast for Shared Costs is \$1.617 million which is \$0.261 million higher than 2016 costs. For SDG&E, shared services activities are Shared Fleet Management. As was the case with SoCalGas, a three-year average was utilized to more accurately reflect recent staffing levels.

24.2.3. IT Business Unit Capital Projects

As stated above, SDG&E is requesting \$2.168 million in 2017, \$4.514 million in 2018, and \$7.632 million in 2019 for the Fleet Upgrade and Fleet Fuel Management projects described in Exhibit 306.³²⁶

24.2.4. Positions of Intervenors

ORA and TURN make the same recommendations and raise the same arguments regarding SDG&E's Ownership Costs and Maintenance Operations as the two parties did regarding SoCalGas' Ownership Costs and Maintenance Operations forecasts. ORA also objects to the adjustment to backfill vacant positions and the adjustment for non-labor maintenance under Maintenance Operations and \$0.144 million for Automotive fuels.

ORA and TURN do not object to SDG&E's forecast for Fleet Management and for Shared O&M Costs.

24.2.5. Discussion

Ownership Costs

SDG&E's TY2019 forecast for Ownership Costs in relation to its historical costs is analogous to that of SoCalGas' in that there is a substantial difference between the TY2019 forecast and historical costs with no adequate explanation regarding the significant disparity. We make the same analogous findings and

³²⁶ Exhibit 306 at 213 to 226.

conclusions as we did in the SoCalGas portion as discussed in section 24.1.4 of the decision. Therefore, we find ORA's recommendation to use 2017 actual costs reasonable as adjusted by adding costs of ATCM compliance replacements, as recommended by TURN in its alternate recommendation. SDG&E's ATCM costs total \$2.009 million as shown in Table CLH-3 of Exhibit 196.³²⁷ As we found in SoCalGas' case, we also find it appropriate to adopt the \$0.170 million representing increase in license fees. This results in a total of \$13.188 million that should be authorized.

Maintenance Operations

ORA and TURN recommend using a three-year average for Maintenance Operations and Automotive Fuels for similar reasons argued by both parties in the SoCalGas section. We reviewed parties' positions and find that a five-year average is more appropriate for both Maintenance Operations and Automotive Fuels for similar reasons as discussed in the SoCalGas section in section 24.1.4 above.

With regards to ORA's adjustment recommendations, we agree with ORA's recommendation to disapprove a \$0.144 million adjustment to Maintenance Operations relating to non-labor maintenance costs associated with incremental vehicles and a \$0.144 million adjustment to fuel costs associated with incremental vehicles. Since both requested increases are associated with incremental vehicles, and we disallow most of the underlying incremental vehicle increases requested under Ownership Costs, we find it appropriate to deny the incremental costs associated with incremental vehicles as well. For the

³²⁷ Exhibit 196 at CLH-7.

FTE positions to be backfilled, we find that the resulting number of FTEs for TY2019 which is 78.6, is not too disparate from historical FTEs, which ranged from 71.7 to 79.4 in 2012 to 2016. In addition, the number of FTEs increased slightly from 2015 to 2016 adding merit to the request. Based on the above, we find that SDG&E's TY2019 forecast for Maintenance Operations should be reduced to \$18.514 million following the two adjustments discussed above.

Fleet Management

We find SDG&E's request for Fleet Management costs to be reasonable and supported by the evidence. Parties do not object to SDG&E's forecast. Therefore, we find SDG&E's \$0.548 million should be authorized.

Shared O&M Costs

We find SDG&E's forecast for Shared O&M costs to be reasonable and supported by the evidence. Parties do not object to SDG&E's forecast. Thus, we find the requested amount of \$1.617 million should be authorized.

IT Capital Projects

We reviewed the two projects and find both projects to be reasonable and necessary. The projects will replace the vehicle management system application and fuel management system application that are now obsolete and no longer supported by the vendor. In addition, the related servers are no longer supported by Microsoft and SDG&E's systems. Therefore, we find that the requested amounts of \$2.168 million in 2017, \$4.514 million in 2018, and \$7.632 million in 2019 should be approved.

24.2.5.1. Summary

Based on the discussions above, the following costs should be authorized for Non-Shared and Shared O&M costs:

Ownership Costs: \$13.188 million

Maintenance Operations: \$18.514 million

Fleet Management: \$0.548 million

Shared O&M: \$1.617 million

**25. Real Estate and
SDG&E Land Services and Facilities**

Real Estate activities pertain to real property asset management and lease administration. Cost centers are made up of different kinds of rent expenses. Land Services concerns the acquisition and negotiation of land rights. Facilities include operational support for utility facilities and maintenance support. SoCalGas' facilities maintenance was discussed as part of the preceding section so only the Real Estate component is discussed in this section.

25.1. SoCalGas

25.1.1. Non-Shared O&M

Non-shared services consist of rent for branch offices and operating bases. SoCalGas also receives services from the Corporate Center for which they are billed.

**25.1.1.1. Branch Offices
and Corporate Real Estate**

SoCalGas is requesting \$2.194 million for rent expenses associated with 37 leased branch offices. SoCalGas utilized a zero-based methodology for its forecast. The forecast for Corporate Real Estate is \$206,000 using a three-year average. Corporate Real Estate provides transaction management and asset management activities for leased or owned real property.

25.1.1.2. Discussion

The leased branch offices are customer payment offices to support bill payment services and walk-in inquiries and we find the cost associated with these to be necessary. Some customers have limited computer access or prefer to

pay their bills in person. The branch offices are also able to address questions from customers about their bill or service.

Rental costs are contractually set. As such, we agree with SoCalGas that a zero-based methodology is appropriate. For Corporate Real Estate, costs have been relatively flat and so a three-year average is appropriate. SoCalGas also owns seven offices and costs associated with these are not included in the GRC. Parties do not oppose SoCalGas' forecast. Based on the above, we find that the requested amount of \$2.4 million should be authorized.

25.1.2. Shared O&M

Shared services are comprised of Gas Company Tower (GCT) rents and Telecom Tower rents. Because there are only two categories, the discussion portion for these two categories is combined following a brief description of these costs and the forecast amount and methodology.

25.1.2.1. GCT Rents

The forecast for GCT Rents is \$19.539 million. Costs are based on annual escalation in base rent plus operating expenses. A zero-based methodology was used to forecast variable costs while actual rent costs are determined by contract.

25.1.2.2. Telecom Tower Rents

The forecast for Telecom Tower Rents is \$1.511 million based on a 4 percent annual inflation.

25.1.2.3. Positions of Intervenors

ORA opposes the forecast for GCT rents and states that using 2017 as a basis is more accurate as rents are determinable from the contract and using the most recent actual data would be more reliable. ORA recommends applying a 2.93 percent annual increase to 2017 rent plus \$1.561 million for the proposed addition of another floor for a total of \$16.156 million which is \$3.383 million lower than SoCalGas' requested amount.

ORA does not oppose the forecast for Telecom Tower Rents.

25.1.2.4. Discussion

From our review, we find that SoCalGas revised its forecast for GCT Rents to \$17.599 million instead of the original \$19.539 million. The revision takes into account amounts for annual landlord rent credits and parking credits that were unintentionally omitted from the 2017 recorded costs that ORA used as a basis for its recommendation. The revised forecast also takes into account revised estimates for base rents, property taxes, janitorial, parking and other operational costs. We find the revision to be reasonable and more reflective of forecast costs for 2019 than either the original forecast or ORA's recommendation as it is based on updated and more complete information. Thus, we find that the revised forecast should be adopted. We also reviewed the forecast for Telecom Tower Rents and find it to be reasonable. Therefore, for Shared O&M costs, we find that \$17.599 for GCT Rents and \$1.511 for Telecom Tower Rents should be approved for a total of \$19.110 million.

25.2. SDG&E

This section includes SDG&E's costs for Real Estate, Land Services, and Facilities maintenance and support and RAMP risks that have been identified in the RAMP Report. The risks that relate to improvement of safety and security include: (a) employee, contractor, and public safety; (b) workplace violence; (c) major disturbance to electrical service; and (d) failure to restore electric services following an event that caused a blackout. Mitigations to address these RAMP risks are included in SDG&E's O&M and capital requests. Only ORA and TURN provided comments, made recommendations, or opposed requests by SDG&E on these costs so discussion of intervenor positions will only involve these two parties.

25.2.1. Non-Shared O&M

25.2.1.1. Facility Operations

The forecast for Facility Operations is \$8.377 million using a three-year historical average. Facilities Operations provide O&M support for utility facilities. This includes maintenance support which is either done by company employees or third-party contractors. Facilities supported include the following:

- a. Construction and operating centers – there are nine facilities used as operating bases for distribution, transmission, and customer service crews;
- b. Branch office – includes four leased and two owned offices that serve as payment locations and provides customer assistance to walk-in customers;
- c. Multi-use and special purpose facilities – includes 10 facilities that serve various functions such as storage, classrooms, field training, maintenance, administrative functions, research and development, hangar for aircraft, etc.; and
- d. Office space.

A significant cost driver for TY2019 is the increase of contracted security services which includes the addition of round-the-clock security services at mission critical substation facilities.

We reviewed SDG&E's forecast and find it to be reasonable. The testimony provides sufficient description of the different activities that are included under this cost category. We find the activities to be necessary to provide operational and maintenance support for different types of facilities. Costs are close to base year levels with the forecast showing an increase of \$70,000 due to increased security services which were partially offset by savings from FOF benefits. We also find the use of the three-year historical average to be appropriate. ORA and TURN do not oppose SDG&E's forecast. Based on the above, we find that the forecast amount of \$8.377 million should be approved.

25.2.1.2. Land Services

The forecast for Land Services is \$693,000 using a three-year historical average. Land Services activities relate to the acquisition and negotiation of land rights for electric and gas distribution and transmission requirements. Land rights are in the form of easements, rights-of-way, licenses, or leases. The Records department also conducts records research for new businesses.

We reviewed SDG&E's forecast and find the proposed forecast to be reasonable and supported by the record. SDG&E provided sufficient justification for the activities proposed and we find the forecast method correctly reflects the anticipated costs for this cost category. Costs are primarily based on labor forecasts and records retention activities. Costs are anticipated to decrease by \$246,000 from base year levels. ORA and TURN do not object to SDG&E's forecast. Based on the above discussion, we find that the forecast of \$693,000 should be approved.

25.2.1.3. Rents and Operating Expenses

The forecast for Rents and Operating Expenses is \$17.513 million³²⁸ using a zero-based methodology. The non-shared portion of rental expenses is for administrative offices, branch offices, customer service facilities, multi-use facilities, telecommunication sites, trailers, and rights-of-ways.

From our review, we find that costs are primarily based on base rents which are determined by contractual agreement. We find the zero-based method to be appropriate as the costs for base rents can be determined. For the variable portions, SDG&E applied a 5 percent annual increase to base rents which we find

³²⁸ This amount was updated from \$18.811 million in the Update Testimony (Exhibit 514) at 24.

to be reasonable. The 5 percent figure is based on average rental increases as presented by SDG&E. For rights-of-way increases, a 10 percent annual increase was applied to the forecast. ORA and TURN did not object to the forecast and we have no objections as well. Therefore, the forecast amount of \$17.513 million for Rents and Operating Expenses should be approved. The annual increases in rents and rights-of-way costs were offset by projected benefits from the Customer Information System project authorized in D.18-08-008.

25.2.2. Shared O&M

There are six cost categories under Shared O&M expenses.

25.2.2.1. Facilities Operations

The request for Facilities and Operations is \$1.287 million using a five-year historical average. Facilities Operations costs pertain to Sempra Headquarters building (Sempra HQ) utilities, facilities manager operation and administrative costs, and the costs for all maintenance expenses for the Rancho Bernardo Data Center (RB Data Center) and Annex.

TURN recommends reducing 50 percent of costs pertaining to the RB Data Center and Annex stating that the decommissioning of the Annex warrants the reduction in costs. The cost corresponding to the RB Data Center and annex is \$758,000 and TURN recommends a reduction of \$379,000. ORA did not object to SDG&E's forecast for Facilities Operations.

In its rebuttal testimony, SDG&E explained that rental costs for the Annex have been already been removed after 2017 and cites a data response to TURN showing the forecast for rent for the Annex as zero for 2018.³²⁹ SDG&E adds that

³²⁹ Exhibit 172, Appendix A at RDT-40 to 41.

actual costs for the RB Data Center and Annex were \$21,000 higher than the \$758,000 that was projected.

We reviewed TURN's recommendation, SDG&E's response, and arguments raised in briefs. We agree with TURN that costs pertaining to rent should not include costs for Facilities Operations and maintenance that are being covered in this subsection. While SDG&E correctly set rental costs for the Annex for 2018 and 2019 at zero, we find that SDG&E did not reduce costs for Facilities Operations in light of the decommissioning of the Annex in 2017. The reduction of rental costs for the Annex to zero should reflect reduced costs for rent and not for Facilities Operations. SDG&E's testimony also states that costs under this category include the Annex. In addition, costs for both the RB Data Center and Annex in 2017 was \$779,000 and yet SDG&E claims that costs projected in 2019 for the RB Data Center alone is at \$758,000 which is nearly equal to the cost in 2017 with the Annex included.

SDG&E has the burden of proving that its requested costs are reasonable and necessary, and we find that SDG&E failed to demonstrate that costs for the Annex in this section are at zero and failed to show that total Facilities and Operations costs were reduced as a result of the decommissioning of the Annex. Thus, we find TURN's recommendation of reducing costs corresponding to the RB Data Center and Annex by 50 percent to be more reasonable than what SDG&E proposes. We shall however add the \$21,000 representing the difference between actual and projected costs for 2017 which results in a reduction of costs by \$358,000. Thus, we find that for Facilities and Operations, \$929,000 should be authorized.

25.2.2.2. Corporate Real Estate

The forecast for Corporate Real Estate is \$646,000 using a five-year historical average. Corporate Real Estate provides strategic asset management, transaction management, lease negotiation, and administrative services and includes due diligence and transaction support.

ORA and TURN do not dispute SDG&E's forecast and we find that the forecast is reasonable and supported by the evidence. Activities in this section are routine activities performed by SDG&E in managing their property assets, leases, and related activities. The request for \$646,000 should be approved.

25.2.2.3. Capital Programs

The TY2019 forecast for Capital Programs is \$129,000 using a three-year historical average. This organization provides overall budgeting, scheduling, tracking, and implementation planning for the annual facilities capital project plan.

There were no objections from ORA or TURN concerning the forecast and we find the forecast to be reasonable and supported by the evidence. We agree that a three-year average is appropriate. We find that the forecast of \$129,000 should be approved.

25.2.2.4. Real Estate – Planning

SDG&E is requesting \$1.073 million for Real Estate Planning using a three-year historical average forecast. This group provides space planning services and coordinates employee moves that include moving furniture and equipment.

We reviewed the request and find it to be reasonable and supported by the evidence. Again, the activities performed by this group are routine activities involving employee and equipment moves and space planning. We find that the

requested amount was sufficiently justified. There were no objections from ORA and TURN and we find that the request for \$1.073 million should be authorized.

25.2.2.5. Real Estate – Resources

The forecast for Real Estate Resources is \$491,000 using a base year recorded forecast methodology. Real Estate Resources supports the Integrated Work Management Software, a workplace technology tool that manages all aspects of corporate real estate. This includes project management, maintenance management, sustainability management, portfolio management, lease management, etc.

We reviewed the forecast and find it to be reasonable. The activities under this section were sufficiently justified by the testimony and we find that these activities are also routine activities performed in managing corporate real estate. ORA and TURN do not object to the forecast and we find the use of base year recorded costs to be appropriate as expenses are mostly flat from 2016. Therefore, the request for \$491,000 should be approved.

25.2.2.6. Corporate Center Maintenance

The forecast for Corporate Center Maintenance is \$2.662 million³³⁰ using a three-year average. Corporate Center Maintenance manages building maintenance services.

ORA does not dispute SDG&E's forecast, but TURN recommends using a four-year average which results in a \$442,000 reduction. In its rebuttal testimony, SDG&E found TURN's use of a four-year average to be reasonable

³³⁰ Revised from \$2.662 million to \$2.220 million in the Update Testimony (Exhibit 514) at Attachment I.

because of a “larger than originally projected variability in the 2017 actual costs.”³³¹

We find no reason to dispute the use of a four-year average methodology as recommended by TURN and agreed to by SDG&E. Thus, we find that the resulting amount of \$2.220 million for Corporate Maintenance Center costs should be approved.

25.2.3. Capital

SDG&E’s capital forecast for Real Estate, Land Services, and Facilities is \$54.699 million for 2017, \$68.502 million for 2018, and \$80.249 million in 2019.³³² This section includes blanket projects which are aggregations of individual projects with a cost of less than \$1 million and special projects with multi-year costs over \$1 million. There are 17 projects in this section. The first nine projects utilize a combination of zero-based and historical spending forecast methodology while the last eight projects, beginning with the Land Service Archibus project, utilize just the zero-based method.

25.2.3.1. Land Blanket

The request for Land Blanket is \$302,000 each in 2017, 2018, and 2019. These blanket projects are for minor maintenance and landscape projects to maintain or improve the value of real property.

³³¹ Exhibit 172 at RDT-8.

³³² Amounts were revised in the Update Testimony (Exhibit 514) at Attachment I to \$54.195 million for 2017, \$65.333 million for 2018 and \$74.356 million for 2019.

25.2.3.2. Structures and Improvements Blanket

The request for this budget is \$1.935 million in 2017, \$4.861 million³³³ in 2018, and \$4.822 million in 2019. This is another blanket project for minor building and site modifications, upgrades, and improvements to increase functionality or extend the life of the asset. Projects include the addition or replacement of basic exterior and interior facilities components such as lighting, fencing, roofing, flooring, windows, paving, etc.

25.2.3.3. Safety/Environmental Blanket

The request for this budget is \$0.909 million in 2017, \$1.504 million in 2018, and \$2.146 million in 2019. This is again a blanket project for building and system upgrades, improvements, and modifications to comply with safety and environmental codes and regulations or to implement best practices towards mitigating environmental risk and employee and public safety. All expenditures are RAMP-related.

25.2.3.4. Miscellaneous Equipment Blanket

The request for Miscellaneous Equipment is \$1.956 million in 2017, \$3.475 million in 2018, and \$2.065 million in 2019. This blanket fund purchase and installation of miscellaneous equipment for numerous departments to address breakdowns but also includes new or replacement equipment used by different departments such as audio visual, mechanical equipment, kitchen equipment, etc.

³³³ Revised from \$4.861 million to \$4.700 million in the Update Testimony (Exhibit 514) at Attachment I.

25.2.3.5. Security Blanket

The request for this budget is \$1.760 million in 2017, \$3.401 million in 2018, and \$4.047 million in 2019. This is another blanket budget to fund building modifications, improvements, and upgrades for security expenditures to safeguard property and protect employees. All expenditures are RAMP-related.

25.2.3.6. Infrastructure and Reliability Blanket

The request for Infrastructure and Reliability is \$1.560 million in 2017, \$1.947 million in 2018, and \$6.651 million in 2019. This is a blanket budget that will fund building facility infrastructure to support building operations with projects such as replacement of equipment and systems that affect reliability and safety and comfort of employees.

25.2.3.7. Remodels and Reconfigurations Blanket

The request for this budget is \$5.605 million in 2017, \$12.984 million in 2018, and \$24.155 million in 2019. This blanket budget will fund changes to occupied facilities in order to provide adequate and efficient office space and work environment for employees. Ergonomic upgrades are included in this budget.

25.2.3.8. Business Unit Expansions Blanket

The request for this budget is \$10.446 million in 2017, \$19.068 million in 2018, and \$16.623 million in 2019.³³⁴ This blanket budget will provide funds for building and facilities expansion and improvements to support business growth

³³⁴ Amounts were revised in the Update Testimony (Exhibit 514) at Attachment I to \$9.942 million for 2017, \$16.060 million for 2018 and \$10.730 million for 2019 by moving the projects in-service dates to after TY2019 but there will be capital spending on this initiative in this rate case cycle as required to progress it through test year 2019 and beyond per Exhibit 172 at RDT-19 and RDT-21.

and initiatives. Projects include expansion, relocation, construction, and planning at and for various facilities.

25.2.3.9. Alternative Energy System Allowance Budget

The request for this budget is \$2.625 million in 2017, \$2.814 million in 2018, and \$5.724 million in 2019. This is another blanket budget, and this will fund the installation of electric vehicle chargers and plug-in receptacles at occupied facilities.

25.2.3.10. Land Services Archibus System

The request for this budget is \$0.756 million in 2017, \$1.008 million in 2018, and \$0.504 million in 2019. The Archibus System is an integrated management system used by Real Estate and Facilities Employees to capture support requests and manage real estate assets and facilities preventive maintenance.³³⁵ The system also automates and develops best management practices of several departments relating to real estate and planning. Costs requested are for re-engineering of systems and processes to meet increased demand and to be able to handle new information.

25.2.3.11. CP6 Call Center Tenant Improvements

The forecast amount for this project is \$2.592 million in 2017. This project is for the improvement of the customer call center at the Century Park Building 6 location.

³³⁵ Exhibit 169 at RBT-38.

**25.2.3.12. RB Data Center
CRAC Replacements**

The forecast for this project is \$1.528 million in 2017. The project will replace ten direct computer room air conditioning (CRAC) units for the RB Data Center server room #1.

**25.2.3.13. CP6 Transmission Energy
Management System**

The request for this project is \$5.199 million in 2017 and \$11.062 million in 2018. This project will improve the infrastructure, visual display systems and equipment, and workstations at the Mission Control Facility which includes the Electric Grid Control Center that provides 24/7 monitoring of SDG&E's electric network. The entire project is a RAMP-related cost.

**25.2.3.14. Mission Control Critical
Asset Hardening**

The forecast for this project is \$2.793 million in 2017 and \$70,000 in 2018. This project will provide upgraded physical security systems and detection devices around the perimeter of the Mission Control facility. The project contemplates the installation of high security fencing that is more resistant to vehicle penetration compared to the chain links and barbed wires currently in place to ensure compliance with North American Electric Reliability Corporation - Critical Infrastructure standards. The entire project is RAMP-related.

25.2.3.15. CP East Tenant Improvements

The request for this project is \$10.943 million in 2017, \$4.494 million in 2018, and \$4.947 million in 2019. The project will provide tenant improvements to roughly 92,000 square feet of newly leased office spaces which are primarily being occupied by departments involved in information technology in light of the termination of associated leases of the Lightwave and Rancho Bernardo Annex A and B properties.

25.2.3.16. Moreno Valley Improvements

The request for this project is \$586,000 in 2017. The project will provide tenant improvements to roughly 7,300 square feet of the Moreno Valley Administrative Building which houses the operating room and support functions for overseeing the flow of high-pressure natural gas from sources to service territories.

25.2.3.17. RB Data Center Reliability Improvements

The forecast for this project is \$3.204 million in 2017, \$1.512 million in 2018, and \$8.263 million in 2019. The project will replace electrical equipment and transfer switches of equipment that are at the end of their useful life and re-circuiting of emergency power distribution from existing 30-year old generators to new generators.

25.2.3.18. Positions of Intervenors

ORA and TURN provided comments, objections, and recommendations to several of SDG&E's forecasts and requests under this section.

ORA recommends lower amounts for the Structures and Improvements Blanket, Safety and Environmental Blanket, Miscellaneous Equipment Blanket, Security Blanket, Infrastructure & Reliability Blanket, and a portion of Business Unit Expansions Blanket. ORA objects to portions pertaining to blanket amounts for unplanned projects stating that the three-year historical average used by SDG&E would encompass both planned and unplanned for projects. For these, ORA also recommends using a five-year average.

ORA also recommends reductions to the Remodels and Reconfigurations Blanket because some related projects were funded without ratepayer funding during the 2016 GRC. ORA also objects to the Kearney Master Plan and Mission Critical Facility Consolidation & Expansion portions of the Business Unit

Expansions Blanket stating that these portions are premature. Finally, ORA recommends a reduction to the Alternative Energy Systems Blanket because the projected increases to electric vehicles to be supported by the project is not at the level that justifies the increased funding being requested.

TURN recommends reductions to the Infrastructure and Reliability Blanket and Remodels and Reconfigurations Blanket because some costs under these blanket projects will not be needed because of another project being planned. TURN also recommends not approving the Kearney Master Plan and Mission Critical Facility Consolidation & Expansion portions of the Business Unit Expansions Blanket for similar reasons to ORA and because these projects will not be completed by the end of 2019.

25.2.3.19. Discussion

We shall first address the disputed projects followed by a collective analysis of the undisputed projects.

Disputed Blanket Projects by ORA

ORA's objections to the Structures and Improvements Blanket, the Safety and Environmental Blanket, the Miscellaneous Equipment Blanket, Security Blanket, the Infrastructure & Reliability Blanket, and a portion of the Business Units and Expansions Blanket are intrinsically for the same reason – which is that historical averages already capture both planned and unplanned for projects. ORA also recommends five-year averages instead of three-year averages.

First, we find that blanket projects are necessary because some of the capital projects for this section are as yet unspecified or unplanned but later on become necessary to improve or maintain an existing asset or for safety, functionality, or other reasons.

We reviewed the six projects above and find that SDG&E's forecast primarily consists of projects that are already planned using zero-based estimates. However, certain years also include blankets of projects that are as yet unplanned for and for these, SDG&E utilized a three-year historical average but subtracted amounts corresponding to planned projects for that same year. Thus, ORA's concern that the planned projects are already captured in the historical average is addressed since these projects are deducted from the three-year average. For example, the three-year average for the Structures and Improvements Blanket is \$4.223 million as shown in the Appendix A to Exhibit 172 at RDT-A-19. The table in page RDT-A-18 of the same exhibit shows that the total of \$2.006 million for four planned projects for 2018 were deducted from the three-year average resulting in \$2.217 million for the unplanned projects. SDG&E then adds estimates for vacation and sick time costs and FERC costs to arrive at its final forecast. If there are no projects to be deducted, then the three-year average is maintained.

We find this methodology to be appropriate since the planned projects captured in the historical averages are deducted from the blanket projects resulting in no double counting.

We find however, that adjustments should be made for the following:
(a) section 25.2.3.2 Structures and Improvements Blanket for 2018 should be reduced to from \$4.861 million to \$4.700 million because of a correction to the actual historical costs;³³⁶ (b) section 25.2.3.3 Safety/Environmental Blanket for 2018 should be reduced from \$1.504 million to \$1.474 million because the \$30,000

³³⁶ Reduction was made in the Update Testimony (Exhibit 514) at Attachment I.

for a planned project was not deducted from the three-year historical average;³³⁷ (c) section 25.2.3.6 Infrastructure and Reliability Blanket for 2018 should be reduced from \$1.947 million to \$1.347 million because \$600,000 for a planned project was not deducted from the three-year average of \$1.332 million;³³⁸ and (d) Infrastructure and Reliability Blanket for 2019 should be reduced from \$6.651 million to \$5.319 million disallowing the request of \$1.332 million for unplanned projects. In this case, SDG&E is requesting for both the historical average amount plus amounts for planned projects inconsistent with deducting the amount for planned projects from the historical average. If there are both planned and unplanned projects, the amount for unplanned projects should be less than the historical average because the historical average should reflect both planned and unplanned projects.

Based on the above, we find that the proposed amounts for the Structures and Improvements Blanket, the Safety and Environmental Blanket, the Miscellaneous Equipment Blanket, the Security Blanket, and the Infrastructure & Reliability Blanket should be adopted subject to the adjustments we enumerated in the preceding paragraph. TURN's concern regarding the Infrastructure & Reliability Blanket will be addressed in our discussion of the Business Units Expansions project.

With respect to using a five-year average versus a three-year average, we agree with SDG&E that using a more current set of projects as a reference better

³³⁷ See Exhibit 172, Appendix A at RDT-A-30 to 31.

³³⁸ *Id.* at RDT-A-25 to 26.

reflects projected projects under this section because more recent needs and trends are taken into account and used as a basis.

Remodels and Reconfigurations

We find that SDG&E provided sufficient evidence and justification for the capital projects included in this blanket including the two projects to which ORA is objecting to, namely the Century 4 and 5 refresh projects. The projects will improve several buildings in and around the company headquarters. The floor plan for some of the buildings have been unchanged for 20 years and need to be reconfigured to better support the needs of SDG&E's employees as opposed to the multiple tenants who were the prior occupants. The fact that related projects were completed without ratepayer funding during the prior GRC does not necessarily eliminate the need for the refresh projects being proposed which we find to have been adequately justified. Similarly, the fact that the buildings are already compliant with American with Disabilities Act standards does not negate other needs and reasons for the proposed projects.

Therefore, the proposed forecasts for the Remodels and Reconfigurations Blanket should be approved. TURN's concern regarding this project will be addressed in our discussion of the Business Units Expansions project.

Business Unit Expansions

ORA and TURN raise similar concerns regarding the Kearney Master Plan and the Mission Critical Facility Consolidation & Expansion. The Kearney Master Plan will support accelerated widespread deployment of distributed energy storage systems while the Mission Critical Facility Consolidation & Expansion's primary aim is to relocate and consolidate critical command center facilities into a single facility with a high level of seismic resistance and increased physical security.

We reviewed the testimony and arguments presented by SDG&E and the opposing arguments raised by ORA and TURN and find that both projects are more appropriately requested and undertaken during the next GRC cycle. We agree with all three parties that the projects are large in scope and as SDG&E states, cannot be completed within one GRC cycle. Because of the scope and complexity of these projects, we find that the projects need to be reviewed more thoroughly and that there is insufficient information to support a comprehensive review at this time. The projects are currently in the pre-planning and planning stages and the timeframe for obtaining necessary permits are mostly uncertain at this time. Although SDG&E is only requesting approval of pre-construction and pre-engineering portions of the projects in this GRC, we find that more information and detail are needed with respect to the actual projects and the different phases thereof which can then be more adequately presented in reviewed in the next GRC.

TURN also objects to the Ramona Construction & Operation Expansion project³³⁹ and for the same reasons given above, we find that this project is also more appropriately requested and undertaken during SDG&E's next GRC because of the scope and complexity of this project similar to the findings made with respect to the Kearney Master Plan and the Mission Critical Facility.

In view of the above, we find that the forecast for the Business Unit Expansions should be adjusted by deducting the amounts requested for the Kearney Master Plan which are \$504,000 for 2017, \$1.512 million in 2018, and \$1.975 million in 2019 and the amounts requested for the Mission Critical Facility

³³⁹ Exhibit 498 at 6 and Exhibit 171 at 68.

which is \$1.496 million in 2018 and \$3.540 million in 2019. The above reductions result in \$9.942 million in for 2017, \$16.06 million for 2018, and \$10.730 million for 2019 that should be adopted for Business Unit Expansions. And, as a result of the denial of approval for the Mission Critical Facility Consolidation & Expansion Projects, TURN's concerns about the redundancy and necessity of specific projects under the Infrastructure and Reliability Blanket and Remodels and Reconfigurations Blanket are addressed.

Alternative Energy Systems

We reviewed the positions of ORA and SDG&E and find that the projects are aimed at supporting increases to SDG&E's alternative fuel vehicles in its fleet as well as its employees that acquire alternative fuel vehicles as their own personal choice of transportation. Encouraging the use of alternative fuel vehicles by providing infrastructure support is in furtherance of the governor's initiatives to reduce fossil fuel emissions and GHG levels. These projects support environmental and societal objectives that benefit ratepayers and the public in general. We find the request to be reasonable and necessary and find that the forecast amounts should be approved.

Other Capital Projects

With respect to the Land Blanket and the projects from section 25.2.3.10 (Land Services Archibus System) to 25.2.3.17 (RB Data Center Reliability Improvements), we find that SDG&E provided sufficient testimony to support the necessity of these capital projects.

The forecast amounts for the Land Blanket are uniform for 2017 to 2019 and the activities described are similar to activities that have been performed in previous years such as landscape and irrigation. The forecast amounts represent

small increases from prior years and are justified by the planned construction of a sturdier fence along the perimeter that provides better security.

We reviewed each of the remaining projects on the list of capital projects in this section beginning with the Land Services Archibus System. All of the projects utilized a zero-based forecast which we find to be appropriate as the scope of each project was considered in the determination of each forecast. The projects were adequately supported by testimony and there were no objections from other parties. Therefore, we find that all of these projects as well as the Land Blanket should be approved without any adjustments to SDG&E's forecasted amounts.

26. Environmental Services

The Environmental Service Organizations for each utility provide guidance and assist in compliance with federal, state, regional, and local government rules and regulations as well as internal policies and procedures in the areas of cultural resources, natural resources, water quality, hazardous materials and waste (HazMat), air quality and land planning.³⁴⁰ This section discusses the O&M forecast for TY2019 for the two utilities.

26.1. SoCalGas

Part of SoCalGas' O&M costs for this section includes a RAMP component pertaining to the safety of employees, contractors, customers, and the public. These risks were identified in Chapter SCG-2 of the RAMP report. RAMP mitigation costs are embedded in traditional activities that were already being performed historically prior to the RAMP process and the TY2019 forecast does

³⁴⁰ Exhibit 295 at DJ-1 and Exhibit 298 at NCC-2.

not include any incremental increases relating to RAMP activities. Specific programs and activities relating to RAMP are environmental and safety compliance program, asbestos safety program, environmental self-assessment, environmental inspection and incident evaluation, environmental training, regulatory monitoring and agency outreach, and service contracting. As with other chapters that include RAMP-related activities, costs relating to RAMP shall be reviewed in our review of the specific O&M activities that make up the forecast for this section.

Pursuant to D.16-06-054, historical and additional costs related to the Aliso Canyon incident are excluded from the forecasting methods that were used.

26.1.1. Non-Shared Services

26.1.1.1. Environmental Programs

Activities under Environmental Programs include management of hazardous waste and Treatment Storage and Disposal Facilities (TSDF) operations, oversight of daily environmental compliance activities and permits, and support for sustainability and compliance with all operations and maintenance and associated facilities.³⁴¹ The forecast for TY2019 is \$6.973 million using a zero-based forecast.

ORA does not oppose the forecast and adds that the increase of around \$1 million from base year levels is because of consolidation with SDG&E's activities. According to ORA, the \$1 million increase for SoCalGas is offset by the around \$1 million decrease for SDG&E.

³⁴¹ Exhibit 295 at DJ-10.

We reviewed the testimony presented and find that the requested amount of \$6.973 million is reasonable and should be approved. The evidence shows that activities and staffing costs under this cost category are necessary to manage hazardous materials and waste control, to maintain various permits, and to conduct tests of all fueling underground storage tank systems. We also agree that the zero-based methodology is appropriate because of the exclusion of historical Aliso Canyon related costs and because compliance requirements have changed.

26.1.1.2. NERBA

SoCalGas requests continuance of the New Environmental Regulatory Balancing Account (NERBA) that has been previously authorized by the Commission. The costs currently authorized to be recorded in the NERBA are: (a) Assembly Bill 32 administrative fees; (b) Municipal Separate Storm Sewer System local ordinance compliance; (c) Subpart W of Part 98 of Title 40 of the Code of Federal Regulations; (d) Leak Detection and Repair Impact Program (LDAR) related costs; and (e) implementation of best practices of the Natural Gas Leak Abatement Program (NGLAP). The forecast O&M costs for NERBA is \$9.634 million. This amount excludes NGLAP costs for 2018-2019 pursuant to D.17-06-015 which directed SoCalGas to file a Tier 3 advice letter for inclusion of these costs into the revenue requirement. A zero-based forecast methodology was utilized to forecast NERBA costs.

26.1.1.2.1. Positions of Intervenors

ORA opposes the forecast for LDAR costs and recommends a 50 percent or \$2.129 million reduction to the \$4.258 million being requested by SoCalGas. ORA does not oppose the forecast for the other components of the NERBA including the \$5.023 million being requested for Assembly Bill 32 costs. ORA

claims that new rules affecting the LDAR do not go into effect until 2018 and the resulting costs from these are uncertain. ORA adds that the two-way balancing account for the NERBA protects SoCalGas from any under-collection. Other parties did not provide any comments regarding this section.

26.1.1.2.2. Discussion

We reviewed the different positions and arguments raised by SoCalGas and ORA concerning the forecast for NERBA and found that the only dispute is with regards to LDAR costs. In its rebuttal testimony, SoCalGas included a response to an ORA data request which provides detailed information regarding the activities that will be performed in connection with LDAR.³⁴² SoCalGas adds that these activities include new rules and regulations from the California Air Resources Board and SB 887. SoCalGas also explained the methodology employed in forecasting these costs. We find that the additional information provided in the data request addresses ORA's concerns about uncertainty regarding the projected costs for the additional activities and ORA did not contest the activities to be performed nor the methodology provided by SoCalGas in making the estimates.

With respect to the mechanism in a two-way balancing account which allows recovery of any over or under-collection, we find that it is more prudent to make the forecast as accurate as possible using all available information and by applying the appropriate forecast methodology. Reliance on the recovery mechanism should be left for unforeseen events to avoid unnecessary and drastic rate adjustments that can be avoided. In this case, SoCalGas provided the

³⁴² Exhibit 297, Appendix A.

information which it used to make its forecast. Based on all of the above, we find that the LDAR costs were sufficiently justified and should be approved.

We also find reasonable the forecasts relating to the other components of the NERBA as well as the continuation of the two-way balancing account for NERBA in this rate case cycle. Therefore, we find that the \$9.634 million requested for NERBA should be authorized as well as continuation of the two-way balancing account for NERBA for this GRC cycle.

26.1.2. Shared Services

26.1.2.1. Director of Environmental Services

The Director of Environmental Services provides leadership and strategic direction for both SoCalGas and SDG&E. Forecast costs for TY2019 is \$75,000 using a zero-based forecast of labor and non-labor costs.

We reviewed the request and find it reasonable and should be approved. The forecast amount is relatively the same as base year levels with only a \$6,000 incremental increase. No party opposed the forecast for this cost category.

26.1.2.2. Environmental Programs

The forecast for Environmental Programs is \$561,000 for TY2019. Compliance activities in this category include air quality compliance and permitting support. Labor costs are shared with SDG&E to maximize efficiency such as reduced travel time and shared expertise. A zero-based forecast was used because historical costs do not represent current activities.

We find the request to be reasonable and supported by the evidence. We also find the forecast methodology to be appropriate. No party objected to the forecast and we find that the forecast amount of \$561,000 should be approved. The total forecast is \$95,000 less than base year levels and no key activity was removed or discontinued.

26.2. SDG&E

26.2.1. Non-Shared Services

The total amount requested for Non-shared O&M services is \$4.851 million which is \$974,000 less than adjusted-recorded expenses for 2016. This amount is being revised to \$5.511 million to include \$0.66 million for Environmental Lab costs which were inadvertently included as a shared service cost as discussed in section 26.2.1.7. Non-shared services are comprised of five cost categories which are discussed below. The forecast methodology utilized for all five cost categories is base year forecasting plus incremental additions or subtractions. ORA does not oppose any of the forecasts made and no other party provided comments to this section.

26.2.1.1. Environmental Field Operations

The forecast for Environmental Field Operations is \$958,000. Activities include managing and maintaining environmental compliance for around 200 facilities and maintaining around 450 environmental permits and plans as well as providing environmental compliance oversight for projects.

We reviewed the evidence submitted and find the request to be justified. The forecasted costs are for labor costs of eight FTEs and fees associated with permits. The requested amount is within 2016 adjusted-recorded levels.

26.2.1.2. Hazardous Material & Waste Management

The forecast for this cost category is \$1.939 million. This section manages and oversees hazardous materials and waste operations including the operation of two treatment, storage, and disposal facilities.

We reviewed the request and find that the cost drivers support the requested amount for this cost category. Projected costs are primarily driven by contracted services with outside vendors and disposal fees for hazardous wastes.

The requested amount is actually \$766,000 less than 2016 levels in part because of savings from FOF initiatives.

26.2.1.3. Site Assessment Mitigation

The forecast for Site Assessment Mitigation is \$228,000. This cost is for costs associated with covered hazardous substance-related activities including hazardous substance cleanup and litigation.

We reviewed the request and find it to be reasonable and necessary. Increased costs for activities resulted in an increase of \$20,000 from 2016 levels which we find to be reasonable.

26.2.1.4. Environmental Programs

The forecast for this cost category is \$741,000. Compliance activities for this area include expenses for specialists that provide guidance on air and water quality, natural resources, cultural resources, project screening for environmental impacts, review of proposed regulations, compliance and oversight of projects, and obtaining environmental permits.

We find the forecast to be reasonable and supported by the evidence. Projected expenses are primarily for consultants and permit fees. The TY2019 forecast is approximately \$282,000 less than 2016 adjusted-recorded expenses.

26.2.1.5. Environmental Permitting, Project Management and Post-Construction

The forecast for this cost category is \$150,000. Projected costs include costs associated with licensing, permitting, and construction and post-construction environmental compliance for capital and O&M projects.

We reviewed the request and find the forecast to be reasonable and supported by the evidence. Activities conducted are necessary and costs are expected to be the same as 2016 levels.

26.2.1.6. NERBA

The forecast cost for NERBA is \$835,000. The currently authorized NERBA is a two-way balancing account that records costs associated with certain new and proposed environmental rules and regulations. The costs recorded are the same as those in SoCalGas' NERBA as described in Section 26.1.1.2 of this decision but with the addition of costs for polychlorinated biphenyls (PCB) phase-out. And similar to SoCalGas' NERBA, costs for NGLAP are excluded in this GRC pursuant to D.17-06-015.

We reviewed the request and the evidence presented and find the TY2019 forecast to be reasonable. Costs for the PCB Phase-out, compliant with subpart W of Part 98 of Title 40 of the Code of Federal Regulations, and LDAR costs are actually set at zero although SDG&E is including these subaccounts in the NERBA in case of unforeseen regulatory requirements that may be imposed. Majority of the costs are for AB 32 Administrative Fees and these fees are for compliance with AB 32. Based on the above, we find that the requested amount of \$835, 000 should be approved. This amount is \$31,000 higher than 2016 adjusted-recorded costs. We also find that the two-way balancing account for NERBA should continue to be authorized in this GRC period.

26.2.1.7. Environmental Lab

Environmental Lab costs are for the operation of the state certified Environmental Analysis Laboratory (Lab). The forecast Lab cost is \$660,000 using a zero-based methodology.

We reviewed the evidence and find that the requested forecast for the Lab should be approved. The forecast is \$431,000 less than 2016 levels because of downsizing and FOF savings. SDG&E provided sufficient justification for necessity of the Lab which performs a broad spectrum of environmental and

chemical sampling, testing and analysis for operational maintenance and regulatory compliance. The Lab was initially included as a shared service cost but the current activities correctly identify it as a non-shared cost.

26.2.2. Shared Services

26.2.2.1. Environmental Services Director

The forecast for the Director and two other shared employees is \$249,000 using a base year method. The Director provides leadership and strategic direction.

We find the forecast method to be appropriate as SDG&E explained why traditional averaging would be inappropriate in this case. We find the request for \$249,000 to be reasonable and should be approved. There was no projected increase from 2016 levels.

26.2.2.2. VP Operations Support

The forecast for VP Operations Support is \$440,000 using a base year methodology. The VP provides leadership and strategic direction.

We reviewed the testimony supporting the forecast and find it to be reasonable and should be approved. The forecast supports the cost for the VP and one executive assistant. The forecast methodology is appropriate as it identifies specific regulatory changes and their related costs. There is no projected increase from 2016 levels.

26.2.2.3. Environmental Communications

The forecast for Environmental Communications is \$758,000 using a base year forecast methodology. The primary function of Environmental Communications is outreach to environmental agencies, tribal leaders, non-government organizations, and other stakeholders and also communicates about sustainability activities.

We find the forecast of \$758,000 to be reasonable and should be approved. The forecast methodology used is appropriate and the testimony supported the cost drivers. The TY2019 forecast shows a \$26,000 increase from base year levels due to a net increase of one position.

27. Information Technology

The IT Division is responsible for many of the technology-related services and activities for SDG&E, SoCalGas, and Sempra. Services include supporting applications, hardware, and software across various fields. IT services relating to Cybersecurity, however, are excluded from costs addressed in this section and will be discussed in a separate section.

The total forecast for O&M costs is \$32.927 million. For capital expenditures, SoCalGas is requesting \$122.653 million in 2017, \$148.498 million in 2018, and \$176.169 million in 2019. FOF savings of \$1.792 million for O&M are included in the forecasts. Costs relating to the Aliso Canyon gas leak incident are excluded from the forecasts and have also been removed from historical information used by impacted witness testimony.

Certain costs are associated with RAMP risk mitigation activities to mitigate key RAMP risks identified in the RAMP Report. These risks are records management and employee, contractor, customer and public safety. Incremental RAMP-related costs for capital expenditure are estimated at \$34.970 million in 2017, \$40.082 million in 2018, and \$36.315 million in 2019. A table listing the RAMP-related IT projects is included in Exhibit 300. Many of the RAMP mitigation efforts listed were initiated because of needs in other business units but are being included in this section because the activities utilize information technology.

27.1. SoCalGas

27.1.1. O&M Costs

As stated above, the TY2019 forecast for O&M costs is \$32.927 million which is \$8.339 million higher than 2016 adjusted, recorded expenses and includes both shared and non-shared costs. Shared costs are estimated at \$11.850 million while non-shared costs are estimated at \$21.077 million. O&M costs are divided into three categories which are Application, Infrastructure, and IT Support. All three categories contain a shared services component as well as a non-shared services component and each category shall be discussed below. All O&M costs were forecast using a base year plus adjustments methodology. SoCalGas explains that using historical costs is not a good basis for predicting future needs as the pace of change in the technology industry continues to accelerate as compared to prior years.

27.1.1.1. Applications

Applications support the development, implementation, and maintenance of computer software utilized by customers, employees, and vendor partners.³⁴³ Shared Applications are typically systems used to support asset management, distribution work management, procurement, supply chain, and financial systems while Applications that relate to customers, customer billing functions, and customer filed operations are generally classified as non-shared. The forecast for TY2019 for Applications is \$14.20 million.

27.1.1.2. Infrastructure

Infrastructure supports the design, implementation, and operation of the computing infrastructure and includes both hardware and software. This

³⁴³ Exhibit 300 at CRO-5.

includes hardware such as desktop systems, servers and storage systems, and software such as middleware,³⁴⁴ production control, operating systems, and other software systems. Shared activities include the operation of data centers that operate around the clock (e.g., servers, storage, and routers), integrating with cloud service providers, monitoring IT systems, supporting the phone system, and operating the IT help desk. The forecast for TY2019 is \$20.009 million.

27.1.1.3. IT Support

IT Support cover costs that are not included under Applications or Infrastructure. Examples include officer costs, budget and planning activities, and the intern/associate program. Shared costs include costs associated with the IT associate program for newly hired IT employees. The forecast for TY2019 is negative \$1.288 million due to savings realized from FOF.³⁴⁵ The savings are associated with removing desktop phones, eliminating duplicative and low value applications, reduced customization of purchased software, procurement and sourcing savings, etc.

27.1.1.4. Positions of Intervenors

Only ORA provided comments to O&M costs and ORA recommends \$25.791 million, or \$7.137 million less than SoCalGas' forecast. ORA states that SoCalGas' forecast for 2017 is approximately 45 percent higher than recorded expenses and utilized an aggregate data method for its recommendation. ORA

³⁴⁴ Middleware is defined as software that acts as a bridge between an operating system and applications, especially on a network.

³⁴⁵ In this case, the savings from FOF are greater than the forecast costs resulting in net savings.

also adds that SoCalGas' workpapers do not provide detailed support for its requests.

27.1.1.5. Discussion

ORA's recommendation is to reduce SoCalGas' shared and non-shared O&M forecasts for 2019 proportionate to the amount that 2017 adjusted, recorded expenses were less than the 2017 forecast. It appears that the rationale for this recommendation is that because SoCalGas spent less than what it had forecast for 2017, then it is expected to also spend less than what its forecast for 2019 by the same proportion.

On the other hand, SoCalGas' testimony shows that it expects costs for routine activities to be around base year levels but requests incremental costs to be added representing additional activities that it plans to perform. SoCalGas presented line item incremental activities for each cost center and explanations for the incremental changes for each of the forecast years.

We evaluated both proposals and find SoCalGas' method to be more appropriate. We find that ORA's approach does not take into consideration the activities to be funded that have been presented and explained in testimony especially the incremental activities that are being planned. The incremental activities are meant to address accelerated change of pace in the technology industry including necessary upgrades for increased computing power, the increasing number and complexity of applications and software, and the increasing commercialization of IT capabilities. ORA did not object to the incremental activities presented by SoCalGas or the need for such and we find the proposed activities to be reasonable and necessary.

In view of the above, we find it reasonable to approve the requested amount of \$32.927 million for O&M costs.

27.1.2. Capital

As stated at the beginning of this section, the forecast for capital expenditures is \$122.653 million in 2017, \$148.498 million in 2018, and \$176.169 million in 2019. All forecasts were prepared using a base year plus adjustments method. The table below shows the breakdown of capital requests made by the IT division and IT-related capital requests by SoCalGas' other business units.

Capital	2017	2018	2019
IT Division	\$50,879,000	\$73,648,000	\$81,227,000
Business Units	\$71,774,000	\$74,850,000	\$94,942,000
Total	\$122,653,000	\$148,498,000	\$176,169,000

The IT-related capital requests by the different business units are included in the testimony sponsored by witnesses for those business units and are discussed in those sections. For example, IT-related capital requests for AMI are discussed in the AMI section. This section will only discuss the capital projects requested by the IT division.

ORA's recommendation is \$120.118 million for 2017, \$132.204 million for 2018, and \$142.629 million for 2019. ORA's recommendation is to apply SoCalGas' recorded, adjusted capital expenditure costs for 2017 and to apply an "ordinary least squares trend"³⁴⁶ for 2018 and 2019. ORA based its recommendation on a budgeted amount for the IT division with individual projects being determined within the budget constraint.

CFC has no objections to the IT-related capital projects for business units but recommends a \$13.9 million reduction to the 2019 forecast for the IT division

³⁴⁶ Exhibit 415 at 18.

and states that there was no quantitative support and no specific benefit accompanying the estimated expenditure. CFC's recommendation is to place an approximately 15 percent limit on the increases for IT capital projects as it argues that 15 percent is a comparative rate of increase with other large companies with respect to IT-related expenditures.

Regarding the recommendations by ORA and CFC for cost reductions to the total forecasts made by SoCalGas, we find that it is more appropriate in this instance to examine each proposed project individually rather than to base the necessity and reasonableness of each proposed project from a single fund or budget from which individual projects will be selected and funded within that budgetary constraint. ORA's method also places significant emphasis on the 2017 adjusted, recorded costs in determining three years of authorized expenditures. Finally, ORA seems to have combined its analysis of the IT capital projects with the Cybersecurity capital projects in stating that SoCalGas' 2017 forecast is 10.6 percent higher than the 2017 adjusted, recorded expenses. Instead, the 2017 forecast for IT is only 2.07 percent higher than adjusted, recorded costs in 2017.

Therefore, we conduct an individual review of each proposed project and base our decision on the merits of each project. In addition, the IT-related capital requests by other business units are discussed in the sections of the decision that address the costs, forecasts, and requests by each of those business units. And as stated above, this section of the decision will address capital projects by the IT division only.

Because there are many similarities among the proposed projects, we combine discussion of all projects to avoid repetitive discussion of similar findings.

27.1.2.1. Gears Upgrade

SoCalGas is requesting \$0.901 million for 2017, \$0.844 million in 2018, and \$0.314 million in 2019 for the Geographic Environmental Analysis and Reporting System (GEARS) project. The project application consists of GIS based data processing tools, map services, and an environmental reporting application. The upgrade will expand functionality, improve efficiency, and refine work hierarchy.

27.1.2.2. Lease Accounting and Reporting System

The forecast for this project is \$0.981 million for 2017, and \$0.758 million in 2018. This project is to enable compliance with the Financial Accounting Standards Board's new accounting standards.

27.1.2.3. Virtual Desktop Expansion

The forecast for this project is \$1.528 million for 2017. This project will expand the current capacity of the virtual desktop infrastructure to enhance its reliability. Virtual desktop infrastructure is virtualization technology that hosts a desktop operating system on a centralized server in a data center.

27.1.2.4. Out-of-Band Management

The forecast for this project is \$0.351 million for 2017. Out-of-band management allows for network support personnel to remotely connect to all sites throughout the service territory. The project will enable faster response times and provide for continuous coverage and support.

27.1.2.5. Self Support Small Cap

The forecast for this project is \$0.944 million each for 2017, 2018, and 2019. The project will be used to purchase replacements for defective, broken, or expired infrastructure and ensure compliance with capitalization policy.

27.1.2.6. Fan – Voice Radio and Dispatch

SoCalGas is requesting \$9.525 million in 2017, \$6.542 million in 2018, and \$4.519 million in 2019. The project will refresh the dispatch and voice radio system by replacing the current communication infrastructure which is at end-of-life.

27.1.2.7. Communications Tip Top Shelter Replacement

The forecast for this project is \$0.553 million in 2017. This project aims to replace the fiberglass and wood shelter at Tip Top with a concrete shelter.

27.1.2.8. Communications Mount David Shelter Replacement

The forecast for this project is \$0.457 million for 2017. The project aims to remodel the concrete communications shelter at Mount David that was purchased from Verizon.

27.1.2.9. Communications Reliability Shelter Replacement (Blythe)

The forecast for this project is \$0.456 million in 2017, \$0.697 million in 2018, and \$0.436 million in 2019. This project is for building a new communications shelter. Pre-deployment work includes installation of new electrical, new direct current plant, and cable tray.

27.1.2.10. Communications Reliability Shelter Replacement (Cactus City Ridge)

The forecast for this project is \$74,000 in 2018 and \$0.662 million in 2019. This project is for building a new communications shelter. Pre-deployment work includes installation of new electrical, new direct current plant, and cable tray.

**27.1.2.11. Communications Reliability
Shelter Replacement (Mt. Solomon)**

The forecast for this project is \$74,000 in 2018 and \$0.662 million in 2019. This project is for building a new communications shelter. Pre-deployment work includes installation of new electrical, new direct current plant, and cable tray.

**27.1.2.12. Communications Reliability
Shelter Replacement (White Water)**

The forecast for this project is \$74,000 in 2018 and \$0.662 million in 2019. This project is for building a new communications shelter. Pre-deployment work includes installation of new electrical, new direct current plant, and cable tray.

27.1.2.13. Session Border Controllers Refresh

The forecast for this project is \$71,000 for 2017. The project plans to refresh the Session Border Controllers hardware and enhance visibility and management.

27.1.2.14. Software Defined Data Center

The forecast for this project is \$4.516 million for 2017. This project will integrate new technology to allow the server, network configurations, and firewall rules to be managed by a single standardized set of tools.

27.1.2.15. Office 365 Enablement and Adoption

The forecast for this project is \$0.853 million for 2017. This project will implement and enable the core Office 365 tool suite and include associated information governance and information security controls.

27.1.2.16. SAP ECC on HANA

The forecast for the Systems Applications Products (SAP) Enterprise Central Component (ECC) on High-Performance Analytic Appliance is \$8.159 million for 2017 and \$3.645 million for 2018. The project will enhance the SAP ECC system with database and application upgrades. The SAP ECC system

is a resource planning software which consists in several modules that provide organizations with great control over their key business processes.

27.1.2.17. GIS Mobile Replacement

The forecast for this project is \$0.974 million for 2017. The project will select and implement a new mobile software application that support service order processing, damage assessment, and mapping discrepancy transmittal posting.

27.1.2.18. Sensitive Data Protection

The forecast for this project is \$5.593 million for 2018 and \$3.286 million for 2019. The purpose of this project is to implement the processes and technologies identified in Sempra's roadmap for protecting sensitive data as it plans to enhance existing data protection capabilities.

**27.1.2.19. Web Portal and
Application Modernization**

The forecast for this project is \$0.905 million for 2018. The project is for building a new standardized web hosting environment which include a self-service web portal and application modernization.

27.1.2.20. Software Defined Data Center Refresh

The forecast for this project is \$10.905 million in 2019. The project will strengthen the data center foundation by integrating current technologies with new technology. This project will also advance existing switch configurations.

**27.1.2.21. Big Data Advanced
Analytic Enablement**

The forecast for this project is \$0.857 million for 2018. The project will enable business areas to perform advanced analytics using large amounts of diverse data and will enable business areas to make more effective data-driven decisions.

27.1.2.22. Enterprise Business Process Management Workflow

The forecast for this project is \$1.789 million for 2018. The project will implement an automated business process management tool which will automate current business processes.

27.1.2.23. Environmental Tracking Enhancements

The forecast for this project is \$0.700 million for 2018. The project will provide enhancements and upgrades and data model expansions to keep pace with regulatory, reliability, and other requirements.

27.1.2.24. SAP Business Intelligence and Analytics Upgrade

The forecast for the SAP Business Intelligence project is \$0.613 million for 2018. The current analytics platform is running on outdated software versions which have resulted in browser incompatibility and other issues. The upgrade will also patch security vulnerabilities.

27.1.2.25. Source Code Management Modernization

The forecast for this project is \$0.429 million for 2018. The project will replace the current integrity application source code management tool because it is outdated and no longer supported by the developer.

27.1.2.26. Enterprise Data Layer

The forecast for this project is \$3.076 million each for 2018 and 2019. The purpose of this project is to build an enterprise data layer that supports re-usability of data integration across common data sources which reduces the needless replication of data.

27.1.2.27. Network Core Refresh

The forecast for this project is \$0.876 million for 2017. The project will implement two standardized data center core networking infrastructures.

27.1.2.28. Enterprise Desktop Refresh

The forecast for this project is \$6.359 million for 2017 and \$3.097 million for 2018. The project will deploy approximately 3,800 Windows 10 workstations of desktops, laptops, and tablets and deploy Office 365 tools.

27.1.2.29. Business Continuity Enhancement

The forecast for this project is \$6.828 million for 2017, \$23.795 million for 2018, and \$33.609 million for 2019. The project will enhance the business continuity capabilities of the data center infrastructure services by implementing high-availability computer, storage, and network services. The project will also migrate critical applications and provide the ability for select applications to remain operative during planned outages.

27.1.2.30. Converged Computing Infrastructure

The forecast for this project is \$3.270 million for 2018 and \$9.361 million for 2019. The project will conduct a phased approach to build out capacity for computer, storage, backup, and network to meet demand of all IT capital projects.

27.1.2.31. Local Area Network Refresh (2018)

The forecast for this project is \$2.455 million for 2018. This project is part of a five-year refresh cycle for local area network switching infrastructure. The existing infrastructure was installed between 2007 and 2009 and is out of warranty and support and software patches and updates are no longer available for a large number of devices.

27.1.2.32. Local Area Network Refresh (2019)

The forecast for this project is \$2.455 million for 2019. This project is part of a five-year refresh cycle for local area network switching infrastructure. The existing infrastructure was installed between 2007 and 2009 and is out of warranty and support and software patches and updates are no longer available for a large number of devices.

27.1.2.33. Private Network Refresh (2018)

The forecast for this project is \$4.055 million for 2018. The project will replace obsolete radio equipment that is at end-of-life and end-of-support. The project will also enable conversion of the microwave system to Ethernet transport. Ethernet transport is used to provide a physical connection to a local area network.

27.1.2.34. Private Network Refresh (2019)

The forecast for this project is \$4.925 million for 2019. The project will replace obsolete radio equipment that is at end-of-life and end-of-support. The project will also enable conversion of the microwave system to Ethernet transport. Ethernet transport is used to provide a physical connection to a local area network.

27.1.2.35. Wide Area Network Refresh (2018)

The forecast for this project is \$3.774 million for 2018. This project is part of a five-year refresh cycle for wide area network routing infrastructure. The existing infrastructure was installed in 2009 and is out of warranty and support and software patches and updates are no longer available for a large number of devices.

27.1.2.36. Wide Area Network Refresh (2019)

The forecast for this project is \$2.512 million for 2019. This project is part of a five-year refresh cycle for wide area network routing infrastructure. The

existing infrastructure was installed in 2009 and is out of warranty and support and software patches and updates are no longer available for a large number of devices.

27.1.2.37. Conference Room AV Upgrade

The forecast for this project is \$2.877 million for 2018. The project will replace audio and video equipment in conference rooms that are outfitted with the legacy system and are no longer functional due to incompatible technologies (ex. analog versus digital).

27.1.2.38. Converged Computing Infrastructure (2017)

The forecast for this project is \$0.223 million for 2017. The purpose of this project is to ensure sufficient capacity for upcoming business demands. The project plans a phased approach to build computing capacity through the acquisition, design, and implementation of components that includes servers, networking components, and data center improvements to accommodate expansion and refresh of aging hardware.

27.1.2.39. Pure Storage Upgrades

The forecast for this project is \$6.324 million for 2017. The project will address storage needs for replication of data, migration of data from the legacy system, and additional network monitoring capability.

27.1.2.40. FOF Operational Awareness

The forecast for this project is \$2.711 million for 2018 and \$2.899 million for 2019. The project will implement a comprehensive application monitoring solution that is capable of detecting issues and deviations. The project will help in detecting and identifying system issues more quickly in order to prevent outages before they occur.

27.1.2.41. Discussion

We reviewed each capital project proposed by the IT Division and find that the proposed projects are necessary and the forecast costs reasonable. The specific details for each project were provided in the workpapers accompanying the testimony submitted. Many of the projects are upgrades or refresh projects to replace obsolete, incompatible, no longer supported by the vendor, or at the end-of-life. The upgrades and refresh projects provide increased performance and functionality to meet business needs that are growing in complexity. SoCalGas is also moving away from certain legacy systems and so equipment and applications relating to those old systems are in need of replacement. Other projects include increasing storage and network capacity to handle increased computing loads. Several projects also impact safety as more data will be used and the new systems will provide better analytics and improved response times in identifying and responding to issues and anomalies. Improvements to the GIS system will support improved analysis of how the physical environment affects SoCalGas' equipment and systems. The projects listed also include improvements to communication centers and improvement to communication equipment in several areas.

ORA and CFC made recommendations to reduce the overall funding requested but did not argue or challenge the necessity of any of the individual projects. And as discussed above, we find that it is more appropriate in this case to review each project individually as we find it more reasonable that necessary projects provide the basis of the funding amount rather than for the funding amount to determine which projects are implemented.

As previously discussed, IT-related capital projects for other business units are addressed and incorporated in the review and discussion of those business units in other sections of the decision.

Based on our analysis and review of each proposed project, we find all of the projects to be necessary and the requested funding levels for each project reasonable. We also find the base year plus adjustments methodology appropriate as historical costs do not reflect the rapid change in technology and the upgrades being planned. Thus, we find that the requested amounts for capital projects for the IT Division of \$50.879 million for 2017, \$73.648 million for 2018, and \$81.227 million for 2019 should be authorized.

27.2. SDG&E

27.2.1. O&M

SDG&E's TY2019 forecast for O&M costs is \$88.449 million which is \$15.071 million higher than 2016 adjusted, recorded expenses and includes both shared and non-shared costs. Shared costs are forecast at \$58.708 million while non-shared costs are forecast at \$29.741 million. Similar to SoCalGas, O&M costs are also divided into the same three categories which are Application, Infrastructure, and IT Support. Descriptions of each of these three categories are the same as those discussed in section 27.1.1.1, 27.1.1.2, and 27.1.1.3 respectively. All three categories also contain both a shared services component and a non-shared services component. All O&M costs were forecast using a base year plus adjustments methodology as SDG&E explains that using historical costs is not a good basis for predicting future needs as the pace of change in the technology industry continues to accelerate as compared to prior years. The individual forecasts for each of the three categories are shown below:

Applications: \$33.742 million

Infrastructure: \$53.436 million

IT Support: \$1.272 million

FOF savings of \$2.946 million for O&M are included in the forecasts. Costs relating to the Aliso Canyon gas leak incident are excluded from the forecasts and have also been removed from historical information used by impacted witness testimony.

Certain costs are associated with RAMP risk mitigation activities to mitigate key RAMP risks identified in the RAMP Report. These risks are records management and employee, contractor, customer and public safety. Incremental RAMP-related costs for capital expenditure are estimated at \$34.970 in 2017, \$40.082 million in 2018, and \$36.315 million in 2019. A table listing the RAMP-related IT projects is included in Exhibit 300.³⁴⁷ Many of the RAMP mitigation efforts listed were initiated because of needs in other business units but are being included in this section because the activities utilize information technology.

27.2.1.1. Positions of Intervenors

ORA and UCAN provided comments to SDG&E's O&M forecast.

ORA recommends using 2017 adjusted, recorded costs of \$76.398 million or \$12.061 million less than SDG&E's forecast. ORA states that SDG&E's forecast for 2017 is approximately 54.2 percent higher than recorded expenses and utilized an aggregate data method for its recommendation. ORA also adds that SDG&E's workpapers do not provide detailed support for its requests.

³⁴⁷ Exhibit 300 at CRO-8 to 10.

UCAN recommends a 15 percent reduction to SDG&E's requested amount for O&M. Similar to ORA's argument, UCAN states that SDG&E's 2017 forecast is much higher than the amount it actually spent. UCAN adds that large capital outlays are atypical of large corporations.

27.2.1.2. Discussion

ORA and UCAN raise the same arguments that ORA raised with respect to SoCalGas' O&M proposals. Similarly, we evaluated the three proposals and find SDG&E's to be more appropriate. As we found with respect to SoCalGas, we find that ORA's approach does not take into consideration the activities to be funded that have been presented and explained in testimony, especially the incremental activities that are being planned. The incremental activities are meant to address accelerated change of pace in the technology industry including necessary upgrades for increased computing power, the increasing number and complexity of applications and software, and the increasing commercialization of IT capabilities. ORA did not object to the incremental activities presented by SDG&E or the need for such and we find the proposed activities to be reasonable and necessary.

UCAN's approach is similar to ORA's and we make the same findings with respect to UCAN's proposal as stated above. UCAN's recommendation simply reduces the overall funding level without considering or objecting to the individual projects being proposed including the necessity thereof and the proposed costs for each project.

In view of the above, we find it reasonable to approve SDG&E's requested amount of \$88.449 million for O&M costs.

27.2.2. Capital Projects

SDG&E's forecast for capital expenditures is \$119.566 million for 2017, \$130.371 million for 2018, and \$139.777 million for 2019. All forecasts were prepared using a base year plus adjustments method. The table below shows the breakdown of capital requests made by the IT division and IT-related capital requests by SDG&E's other business units.

Capital	2017	2018	2019
IT Division	\$38,373,000	\$50,414,000	\$80,924,000
Business Units	\$81,193,000	\$79,951,000	\$58,853,000
Total	\$119,566,000	\$130,371,000	\$139,777,000

This section will only review IT capital expenditures of the IT Division. IT-related capital requests by the different business units are included in the testimony for those business units and are discussed in those sections.

ORA's recommendation is \$121.095 million for 2017, \$99.672 million for 2018, and \$115.524 million for 2019. ORA's recommendation is to apply SoCalGas' recorded, adjusted capital expenditure costs for 2017 and to apply an "ordinary least squares trend"³⁴⁸ for 2018 and 2019. ORA based its recommendation on a budgeted amount for the IT division with individual projects being determined within the budget constraint.

CFC has no objections to the IT-related capital projects for business units but recommends a reduction of \$30.2 million to the 2019 forecast for the IT division and states that there was no quantitative support and no specific benefit accompanying the estimated expenditure. CFC's recommendation is to place a 15 percent limit on the increases for IT capital projects in 2019.

³⁴⁸ Exhibit 415 at 18.

UCAN recommends a 15 percent reduction to 2019 capital expenses in part because SDG&E's forecast methodology has proven to be inaccurate in the past and the same forecast methodology is being utilized with regards to the proposed forecasts. UCAN also suggests that IT costs for the LTE Communications Network project be "levelized" over a two-year period.

Regarding the recommendations by ORA and CFC, as we discussed in the SoCalGas portion of this section, we find that it is more appropriate in this instance to examine each proposed project individually rather than to base the necessity and reasonableness of each proposed project from a single fund or budget from which individual projects will be selected and funded within that budgetary constraint. In addition, ORA and CFC did not object to the necessity or costs of any of the individual projects.

Thus, we find it more appropriate to conduct an individual review of each proposed project and base our decision on the merits of each project. In addition, the IT-related capital requests by other business units are discussed in the sections of the decision that address the costs, forecasts, and requests by each of those business units. And as stated above, this section of the decision will address capital projects by the IT division only.

Because there are many similarities among the proposed projects, we combine discussion of all projects to avoid repetitive discussion of similar findings. UCAN's objections and recommendations will also be addressed in said discussion.

27.2.2.1. Private Network Refresh

SDG&E is requesting \$0.856 million for 2017. The project will upgrade nine existing microwave radio backbone links to provide network redundancy,

added capacity, four additional links, and to replace end-of-life and end-of-support devices.

27.2.2.2. Transmission Communication Reliability Improvement

The forecast for this project is \$10.324 million for 2017. This project will transform existing communication inter-site infrastructure of selected substations to internet protocol and multiprotocol label switching which offers advanced capabilities such as diverse communication paths, intelligent rerouting, monitoring, and alerting and correlation capabilities.

27.2.2.3. SCADA Radio Replacement and Expansion

The forecast for this project is \$1.861 million for 2017. This project will replace aging SSCADA equipment with newer technology with enhanced security features such as communication encryption and endpoint authentication.

27.2.2.4. Out-of-Band Management

The forecast for this project is \$0.372 million for 2017. Out-of-band management allows for network support personnel to remotely connect to all sites throughout the service territory. The project will enable faster response times and provide for continues coverage and support. SDG&E plans to deploy 700 out-of-band devices.

27.2.2.5. ADMS Phase 3

The forecast for the Advanced Distribution Management System project is \$1.102 million for 2017 and \$0.133 million for 2018. The project will upgrade and configure major net minecraft server code lines and related infrastructure.

27.2.2.6. Data Warehouse and Hadoop Platform Upgrade

SDG&E is requesting \$1.066 million in 2017 and \$1.335 million in 2018. The project aims to ensure that all at-risk data warehouses can continue to operate to meet business requirements by leveraging an open source extract, transform, and load for data staging and transformation.

27.2.2.7. Electronic Bill Presentment and Payment

The forecast for this project is \$1.591 million in 2018. Current gas billing processes require a paper invoice to be mailed out and the payer can only pay for services with a physical check. This project will utilize billing software that provides electronic billing that is run through a billing portal.

27.2.2.8. MDT Technology Obsolescence 2018/2019

The forecast for this project is \$1.268 million for 2018 and \$1.237 million in 2019. The project is for the replacement of Mobile Data Terminals (MDT) utilized by field personnel. Field personnel rely on this equipment to respond to storms, outages, etc.

27.2.2.9. MDT Technology Obsolescence 2016/2017

The forecast for this project is \$1.015 million for 2017 and \$0.160 million in 2018. This project will replace around 529 MDT units used by field personnel. The replacement is being done in accordance with guidelines outlined in the MDT standards for MDT life cycle which replaces these units which are used on a daily basis every four years.

27.2.2.10. LTE Communications Network

The forecast for the Long-term Evolution Communications Network project is \$22.889 million in 2018 and \$50.262 million in 2019. The project plans to

replace existing wireless communications infrastructure which has become inadequate to meet demand for greater volumes of data at high speed.

Expanding the systems will also provide coverage for a wider area. In addition, the Federal Communications Commission's grandfathered protection of the use of 3.65 GHz frequency licenses will expire in 2020 and the project will utilize a broadband wireless digital communications network.

27.2.2.11. Downtown SCADA Modernization

The forecast for this project is \$1.210 million for 2017, \$3.745 million for 2018, and \$5.689 million for 2019. This project will provide communication infrastructure upgrades that will service the downtown San Diego area. Several remote terminal units will be replaced with internet protocol communications.

27.2.2.12. Enterprise Desktop Refresh

The forecast for this project is \$2.928 million for 2017. The project will refresh existing workstation hardware which will provide increased memory and processing power to be able to run advanced applications.

27.2.2.13. Server 2016 Enterprise Environment

The forecast for this project is \$1.320 million for 2017. The project will provide software and hardware upgrades to the Structured Query Language (SQL) shared database. The SQL database supports over 1500 databases for key business areas and the current database servers have already gone out of support and do not support initiatives for handling encryption.

27.2.2.14. Mainframe Capacity Hardware Upgrade

The forecast for this project is \$2.273 million for 2018 and \$4.575 million for 2019. The purpose of this project is to increase mainframe capacity to address continued mainframe growth.

27.2.2.15. Private Network Expansion and Refresh Phase 3

The forecast for this project is \$4.239 million for 2017. The project is for building a new standardized web hosting environment which include a self-service web portal and application modernization. The project will replace obsolete microwave hardware and communication infrastructures that are at end-of-life and end-of-support. The project will also enable conversion of the microwave system to internet protocol microwave radios with synchronous Ethernet capabilities.

27.2.2.16. Private Network Expansion and Refresh Phase 4

The forecast for this project is \$3.674 million for 2018. The project will replace obsolete microwave hardware and communication infrastructures that are at end-of-life and end-of-support. The project will also enable conversion of the microwave system to internet protocol microwave radios with synchronous Ethernet capabilities.

27.2.2.17. Transmission Communications Enhancement Phase II

The forecast for this project is \$6.769 million for 2017, \$12.711 million for 2018, and \$14.631 million for 2019. Phase II of this project will standardize the network communication inter and intra-site infrastructure and further address single points of failure in the network by providing diverse communication paths and intelligent rerouting.

27.2.2.18. NOC Modernization

The forecast for the Networks Operation Center (NOC) project is \$4.258 million for 2017. The project will upgrade the NOC to keep up with current and future demands as the company has added new services,

applications, network upgrades, circuits, and users which has doubled the demand for the NOC.

27.2.2.19. Self Support Small Cap

The forecast for this project is \$0.500 million for 2017 and \$0.635 million each for 2018 and 2019. The funding for this project will cover multiple small capital projects covering routine business customer operational issues such as safety, network improvements, information security, faster service, etc.

27.2.2.20. WAN Life Cycle Extension

The forecast for this project is \$0.310 million for 2017. The project will replace end-of-life and end-of-sale core devices for eight wide area network locations. The life cycle extension will extend vendor support, system reliability, and provide the ability to meet evolving client requirements.

**27.2.2.21. Private Network
Expansion & Refresh Phase 5**

The forecast for this project is \$3.895 million for 2019. The purpose of this project is to upgrade or replace aging microwave communication infrastructures with more advanced hardware and internet protocol microwave radios.

27.2.2.22. Mainframe Capacity Upgrade

The forecast for this project is \$25,000 for 2017. The project will replace SDG&E's mainframe hardware with an upgraded configuration that will satisfy current mainframe capacity demands.

27.2.2.23. Smart Grid Endpoint Protection

The forecast for this project is \$0.218 million for 2017. The project will test and deploy endpoint protection technologies to Smart Grid servers and workstations in data centers, control centers, and substations.

27.2.2.24. Discussion

As previously discussed, IT-related capital projects for other business units are addressed and incorporated in the review and discussion of those business units in other sections of the decision and the discussion here will address the proposed capital projects by the IT Division.

We reviewed each capital project proposed by the IT Division by examining the supporting testimony and workpapers. The specific details regarding each project appear in the workpapers and capital workpapers of witness Olmsted.

Many of the projects are for improvements and upgrades to SDG&E's communications systems and infrastructure. The projects replace outdated technology that is near or at the end of its life and have limited support or are no longer being supported by the vendor. The projects are also aimed at increasing functionality to meet business needs that are growing in complexity. Other projects are also aimed at increasing compatibility with newer systems as SDG&E continues to move away from microwave technology. Several projects will increase capacity and memory in order to handle future business needs. The new systems will also provide faster communication speeds that are more reliable and able to handle bigger loads on the system. Based on our review, we find the proposed projects to be necessary for SDG&E to modernize its communication infrastructure to meet present and future demands.

With regards to the LTE Communications Network, we find the testimony and workpapers adequately support the project. In response to UCAN's arguments about the project being poorly documented, SDG&E provided that its proposals were carefully evaluated and various vendors were consulted. Alternatives were also explored including staying with the current system.

SDG&E also utilized industry and technical experts in evaluating the project. The project will allow communication with all locations in SDG&E service territory and is likely to improve SDG&E's ability to respond to natural disasters.

Based on the above, we find that SDG&E conducted sufficient due diligence with regards to the project as well as exploring less expensive alternatives which are important steps considering the size and cost of the project. With regards, the leveling costs over a two-year period, UCAN did not provide sufficient analysis and basis for this recommendation such as whether the project can be broken up into several phases.

And as discussed above, we find that it is more appropriate in this case to review each project individually as we find it more reasonable that necessary projects provide the basis of the funding amount rather than for the funding amount to determine which projects are implemented.

Based on our analysis and review of each proposed project, we find all of the projects to be necessary and the requested funding levels for each project are reasonable. We find the forecast methodology that was utilized to be reasonable and agree with SDG&E that historical costs do not reflect the rapid change in technology and the upgrades being planned.

Thus, we find that the requested amounts for capital projects for the IT Division of \$38.573 million for 2017, \$50.414 million for 2018, and \$80.924 million for 2019 should be authorized.

28. Cybersecurity

The Cybersecurity Department is responsible for cybersecurity risk management of the information and operational technologies of SDG&E,

SoCalGas, and Sempra.³⁴⁹ The department is focused on maintaining and improving the companies' security posture and reducing the likelihood and impact of cybersecurity incidents while balancing costs through prioritized risk management. The department also provides technical support and training to other departments. Cybersecurity is a completely shared service.

28.1. RAMP

Cybersecurity is one of the top safety risks that was identified in the RAMP Report.³⁵⁰ Major cybersecurity incidents can lead to disruptions to electric and gas operations and company operations and can result in disclosure of sensitive data and damage to the company's reputation. In their assessment of cybersecurity risks, SDG&E and SoCalGas relied on the risk "bow tie"³⁵¹ which lists potential drivers that lead to a risk event and potential consequences of a risk event.

The Cybersecurity Department is responsible for identification and management of cybersecurity risks and the Cybersecurity Program identifies risks and the projects, practices, and controls used to manage the identified risks. The program focuses on responding to potential risk drivers and resulting events for risks that are known but also strives to implement mitigations and protections to address unknown risks.

Resources are prioritized on addressing known risks and management activities apply best practices, acceptable use policies, security standards, and technology resources for managing and maintaining technology systems. Risks

³⁴⁹ Exhibit 308 at GW-1 and Exhibit 311 at GW-1.

³⁵⁰ RAMP Report Chapters SCG-03 and SDG&E-07.

³⁵¹ Exhibit 308 at GW-7 and Exhibit 311 at GW-6.

are identified by using multiple sources of information and risk mitigation practices are based on the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF),³⁵² which according to Applicants, is the current foundational document used as the cybersecurity risk management framework.

Risk controls and best practices to reduce and manage cybersecurity risks in order to improve security and resilience of critical infrastructure are grouped into five core functions which are: identify; protect; detect; respond; and recover. RAMP-related activities for cybersecurity are included in SDG&E's and SoCalGas' requests for O&M costs and capital projects. Almost all the requests for cybersecurity O&M and capital are RAMP related. The specific cost categories and capital projects for SDG&E and SoCalGas will be discussed below.

28.2. SoCalGas

28.2.1. O&M Costs

SoCalGas is requesting \$708,000 for O&M costs relating to cybersecurity with the primary cost driver being the escalating costs associated with the addition of on-site staff to provide cybersecurity consulting support to other business units during the development and implementation of projects by those business units in order to enhance cybersecurity. All O&M costs are RAMP-related.

Only ORA provided a position on SoCalGas' O&M proposal for cybersecurity and ORA recommends reducing SoCalGas' requested amount by approximately 20.5 percent to \$588,000 based on the fact that SoCalGas' 2017

³⁵² The NIST CSF was developed through the collaboration between the Federal Government and the private sector to address and manager cybersecurity risk cost effectively based on business needs pursuant to Executive Order 13636.

forecast exceeded its adjusted, recorded expense in 2017 by approximately 20.5 percent.

The sole management category that comprises the O&M portion of cybersecurity for SoCalGas is Access Management.

The Access Management or Security Engineering Group is comprised of Information Security and Consulting, Production Support, and Security Operations. Respectively, the three groups provide: cybersecurity consulting services aimed at reducing risks; management of security technologies including firewalls and intrusion detection and prevention; and support for access controls and endpoint security.

SoCalGas' forecast methodology is to use base year 2016 costs plus adjustments. On the other hand, ORA recommends using recorded 2017 costs because the adjusted, recorded costs in 2017 were 20.5 percent less than SoCalGas' forecast which is almost identical in amount to its forecast for 2019.

We have reviewed the testimony presented by SoCalGas and ORA as well as the arguments raised by the two parties in briefs and find SoCalGas' forecast methodology to be reasonable. SoCalGas based its forecast and considered increased activities in other areas due to RAMP and other changes to SoCalGas' operational environment as well as the increased number of systems and activities that would need to be supported by the Access Management Group.

The Access Management Group provides support to projects and ensures the security of applications and the system before the projects are placed in production and manages cybersecurity technologies³⁵³ and we find it reasonable

³⁵³ Exhibit 308 at GW-22 to 23.

to assume that there will be more activities and systems that will need cybersecurity support in 2019 as compared to 2017 due to increased activities relating to RAMP and other areas. In addition, ORA did not provide adequate reasons why it assumes that O&M expenses for cybersecurity in 2019 are expected to be at the same level as O&M expenses for 2017. Therefore, we find SoCalGas' forecast of \$708,000 to be reasonable and adopt it.

28.2.2. Capital

SoCalGas requests \$17.844 million for 2017, \$19.476 million for 2018, and \$22.731 million for 2019 for cybersecurity capital projects. On the other hand, ORA recommends \$6.882 million for 2017, \$7.201 million for 2018, and \$7.896 million for 2019. All of the costs for capital projects for 2017 to 2019 are RAMP-related. ORA's recommendation is to apply SoCalGas' recorded, adjusted capital expenditure costs for 2017 and to make proportional reductions to SoCalGas' requests for 2018 and 2019 applying an "ordinary least squares trend."³⁵⁴

However, we find that it is more appropriate in this instance to examine each proposed project individually rather than to base authorized expenditures for three years from the recorded expenditures from a single year without examining the actual projects being proposed. Many of the proposed capital projects are pursuant to SoCalGas' increased efforts to mitigate cybersecurity risks as a result of the RAMP process and these projects and increased efforts are not reflected in historical costs. Therefore, we shall conduct an individual review of each proposed project and base our decision on the merits of each project.

³⁵⁴ Exhibit 415 at 18.

Because there are many similarities among the proposed projects such as the forecast methodology and the basis for costs being the purchase of new hardware and software and associated labor costs, we shall combine discussion of all projects to avoid repetitive discussion of similar topics such as those mentioned above.

28.2.2.1. Enterprise Threat Intelligence

SoCalGas is requesting \$1.474 million for 2017 and utilized a zero-based forecast. This project aims to refresh technology at the ends of its life and expanding capabilities to address a broader range of threats and to enable integration with other detection and response systems. The project provides the ability to recognize and act on indicators of an attack. Projected costs are for the purchase of new hardware and software and also labor costs to design, implement and integrate the solution with related systems.

28.2.2.2. Threat Identification Systems

The forecast for this project is \$4.731 million for 2019 utilizing a zero-based forecast. This project will implement multiple capabilities in order to identify and assess cybersecurity risks. These capabilities are in addition to other threat intelligence and risk assessment capabilities and involve the purchase of new hardware and software and labor costs for design, implementation and integration with related systems.

28.2.2.3. Cloud Access Security Breaker Cloud Data Use

The forecast for this project is \$2.893 million for 2018 utilizing a zero-based forecast. This project will provide security monitoring of cloud-based services, policy enforcement of cloud applications, and cloud based data loss prevention. The project involves the purchase of new hardware and software and labor costs for design, implementation, and integration.

28.2.2.4. Critical Gas Infrastructure Protection

The forecast for this project is \$1.674 million for 2017, \$2.291 million for 2018, and \$4.232 million in 2019. SoCalGas utilized a zero-based forecast. This project's purpose is to implement multiple capabilities to prevent or detect cybersecurity risks with the aim of minimizing the likelihood of risks and impacts to critical gas infrastructure systems. The project involves the purchase of new hardware and software and labor costs for design, implementation, and integration with related systems. The project includes access control, data security, maintenance, protective technology capabilities, detection of anomalies and events, and continuous security monitoring.

28.2.2.5. Enterprise Source Code Security

The forecast for this project is \$1.18 million for 2018 and \$36,000 for 2019 using a zero-based forecast. The project will provide proactive preventative application scanning and static analysis of source code before software is released into production. This will reduce the likelihood of unauthorized activity and impact to safety and reliability. The project includes the purchase of new hardware and software and labor expenses for design, implementation and integration.

28.2.2.6. Firewall Security

SoCalGas is requesting \$308,000 in 2017 for this project using a zero-based forecast methodology. The project will implement a firewall rule configuration management tool to maintain consistent configuration and support change management which is aimed at reducing the likelihood of unauthorized activity. The project includes the purchase of new hardware and software and labor costs for design, implementation, and integration with related systems.

28.2.2.7. Information Security Zone Rebuild

The forecast for this project is \$901,000 for 2017 using a zero-based forecast. This project aims to refresh aging server hardware and networking infrastructure which is no longer supported by the vendor before equipment failure. Costs are for hardware and software purchase and labor for design, implementation and migration to the new system.

28.2.2.8. Multi Factor Authentication Refresh

The forecast for this project is \$2.640 million for 2018 utilizing a zero-based forecast methodology. The project aims to refresh, extend, and enhance the multi-factor authentication capability used to increase confidence in a user's authentication credentials. Costs are for hardware, software and labor for design, implementation, and integration with related systems.

28.2.2.9. My Account Multi Factor Authentication

The forecast for this project is \$479,000 in 2019 utilizing a zero-based forecast. This project will implement several multi-factor authentication capability options for customers to protect customer information and includes the purchase of new hardware and software and labor costs for design, implementation, and integration with related systems.

28.2.2.10. Public Key Infrastructure Rebuild

The forecast for this project is \$58,000 in 2017 utilizing a zero-based forecast. The project seeks to update obsolete cryptography that is used to identify devices and applications and protect in-transit data. The project includes purchasing new hardware and software and labor costs for design, implementation, and integration.

28.2.2.11. E-Mail Spam Protection

The forecast for this project is \$1.086 million in 2017 using a zero-based forecast methodology. This project is to refresh the system used to identify and

block email spam, phishing, and malware defense for all internal and external email. Costs for the purchase of new hardware and software and labor costs to design, implement and integrate with related systems and to test for functionality.

28.2.2.12. Security Orchestration

The forecast for this project is \$1.705 million in 2017 and \$185,000 for 2018 utilizing a zero-based forecast methodology. This project will implement a security orchestration infrastructure that automates repeatable tasks which will allow analysts to focus on higher value tasks. Costs are for hardware and software purchases and labor costs for design, implementation, integration and testing for functionality.

28.2.2.13. Web Application and Database Firewalls

The forecast for this project is \$2.228 million for 2018 using a zero-based forecast. The project plans to implement a technology to provide an added layer of protection to alert and block internet-based attacks targeting web applications and databases. The project includes the purchase of new hardware and software and labor costs for design, implementation, and integration with related systems.

28.2.2.14. Wired Network Preventative Controls

The forecast for this project is \$3.375 million for 2018 and \$60,000 for 2019 using a zero-based forecast methodology. This project will implement protective controls to manage device access to wired networks at all facilities and field sites. The project will provide additional risk mitigation for managing device access to wired networks and includes the purchase of new hardware and software and labor costs for design, implementation, and integration with related systems.

28.2.2.15. Insider Threat Detection/Prevention

The forecast for this project is \$1.843 million in 2017 using a zero-based forecast. The project will deploy new anomaly detection technologies as well as enhancements to existing security technologies. The project provides additional capabilities in detecting anomalies in behavior and network activity and includes the purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.16. Network Security Monitoring

The forecast for this project is \$1.770 million in 2017 and \$146,000 for 2018 using a zero-based forecast. The project will implement a consolidated network security monitoring capability which will enhance capabilities in monitoring the flow of data at key network transit points. The project includes the purchase of new hardware and software and labor costs for design, implementation, integration with related systems and testing for functionality.

28.2.2.17. Perimeter Tap Infrastructure Design

The forecast for this project is \$1.331 million for 2018 using a zero-based forecast methodology. The project will implement a network device in the network perimeter to support cybersecurity and network monitoring tool connections to help reduce the likelihood of unauthorized activity. The project includes the purchase of new hardware and software and labor costs for design, implementation, integration and testing of functionality.

28.2.2.18. SCG Network Anomaly Detection Phase I

The forecast for this project is \$1.744 for 2017 using a zero-based methodology. The project will deploy industrial control systems and SCADA network anomaly detection devices into the gas infrastructure to detect and provide alerts on anomalous network activity. Costs include purchase of new

hardware and software and labor costs for design, implementation, integration and testing for functionality.

28.2.2.19. SSL Decryption

The forecast for the Secure Sockets Layer (SSL) project is \$296,000 for 2017. The purpose of this project is to improve the inspection of network data at the perimeters of data centers and to help address evolving threat capabilities that utilize SSL encryption. Costs include the purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality of the new system before it is put into service.

28.2.2.20. Threat Detection Systems

The forecast for this project is \$4.732 million in 2019 utilizing a zero-based forecast methodology. The project will implement multiple capabilities to detect cybersecurity risks to critical infrastructure systems and support use of new technologies not addressed elsewhere. The capabilities that will be added are in addition to other detection system capabilities. The project includes the purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.21. Forensics Systems Rebuild

The forecast for this project is \$202,000 for 2017 utilizing a zero-based forecast methodology. The project is a refresh of the technology supporting forensics business processes and infrastructure. Costs include the purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.22. Incident Response Secure Collaboration

The forecast for this project is \$1.914 for 2018 using a zero-based forecast method. The project plans to build a scalable communication and coordination

platform to coordinate incident response activities which will help reduce the likelihood of unauthorized activity by supporting a more responsive and adaptive detection capability. Costs include the purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.23. Threat Response Systems

The forecast for this project is \$4.231 million in 2019 using a zero-based methodology. The project will implement multiple and additional capabilities to respond to cybersecurity risks and will support new technologies for threat response by critical infrastructure systems not addressed elsewhere. Costs include purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.24. Threat Recovery Systems

The forecast for this project is \$4.230 million in 2019 using zero-based forecasting. The project aims to implement multiple capabilities to recover from threat that are in addition to existing systems. Costs include the purchase of new hardware and software and labor costs for design, implementation, integration, and functionality testing.

28.2.2.25. Converged Perimeter Systems

The forecast for this project is \$2.516 million in 2017 and \$1.270 million in 2018. The project will focus on firewalls and intrusion prevention devices at the data center perimeters. The project will consolidate perimeter network protections into a single platform and includes purchase of new hardware and software and labor costs for design, implementation, integration, and testing for functionality.

28.2.2.26. Host Based Protection

The forecast for this project is \$2.267 million in 2017 and \$23,000 in 2018. The project will investigate and implement an endpoint security solution that will allow an endpoint to be protected in a hostile environment. Servers and workstations will be included in the scope and allows for protection even when located outside a protected perimeter such as being placed in a cloud environment. Costs for this project include purchase of new hardware and software and labor costs for design, implementation, integration with related systems, and testing for functionality.

28.2.2.27. Discussion

We have reviewed each capital project proposed by SoCalGas for Cybersecurity to determine the necessity and reasonableness of each project. We reviewed the testimony of SoCalGas' witness as well as the accompanying workpapers that provide specific details and cost components for each project. We also reviewed pertinent sections of the RAMP report referenced or associated with the projects and reviewed the arguments SoCalGas raised in its brief. None of the other parties provided analysis regarding these specific projects except for ORA's recommendation to reduce the total amount of funding for capital projects which we have discussed at the beginning of this section.

Based on our analysis and review of each proposed project, we find all of the projects to be necessary and the requested funding levels for each project reasonable. SoCalGas provided sufficient evidence to support and justify these projects. All of the projects are associated with SoCalGas' enhanced focus and efforts in mitigating, preventing, and managing cybersecurity risks and incorporating a risk-based framework into their GRC request. Cybersecurity is one of the top safety risks identified in the RAMP report and the assessment for

some of the areas that are being addressed by the requested projects have impact scores of extensive or severe as shown in the RAMP report. Each project addresses an area of cybersecurity that SoCalGas is seeking to manage. We agree with SoCalGas that cybersecurity-related issues have become more complex and the potential impacts of attacks have become much larger in scope over the years. Thus, it is necessary to update, upgrade, and expand SoCalGas' ability to detect, respond, protect, and/or mitigate against potential cybersecurity attacks.

Some of the projects appear to have overlaps with other projects and we examined these projects closely. For example, the My Account Multi Factor Authentication appears to have overlaps with the Multi Factor Authentication Refresh project. Both projects seek to enhance user authentication capabilities to ensure that only authorized persons are able to access SoCalGas' database. From our review, we note however that one project focuses on authentication of employees while the other focuses on authentication of customers and the authentication protocols for these two types of users differ. Since employees and trusted contractors have privileged access to critical IT systems and have greater ability to cause damage, more robust technologies and solutions are necessary to safeguard employee access. Because the security requirements differ, we find it prudent from a cost perspective to separate the solutions required for the authentication of customers versus the more robust solutions required for protecting employee access.

Another example of a seeming overlap is with respect to the Threat Recovery Systems project planned for 2019. This project seeks to provide capabilities that are in addition to what other systems and projects will or are already providing. This project also appears to provide supplemental functions to the Threat Detection Systems and Threat Response Systems. However, we

examined these projects closely and find that the ubiquity of successful data breaches in recent years means that not all threats can be successfully mitigated. To address these changes in the threat landscape, there is a renewed emphasis on having the ability to rapidly recover from an attack or breach and threat recovery systems that are designed to protect business critical processes across systems, have become necessary.

We also note that overlapping protections are sometimes necessary to afford adequate protection from multiple and enhanced threats and to reiterate, we examined all 25 projects being proposed and find each one to be necessary.

We also find that a zero-based forecast is more appropriate than ORA's proposed approach for the proposed cybersecurity capital projects because of the wide range of risk drivers. Rapid changes in technology, innovations in business methods, and evolving threats and the sophistication level of attacks are better addressed by specific costs relating to each project rather than historical data which may not be existent since many of the proposed projects involve new functions and capabilities and the addition of new hardware and software. All of the projects are also a result of or are directly related to SoCalGas' adoption of a risk-based framework which is being incorporated into its GRC requests for the first time.

Based on the above, we find that the requested amounts for capital projects under cybersecurity for 2017, 2018, and 2019 should be authorized.

28.3. SDG&E

28.3.1. O&M

SDG&E is requesting \$7.907 million for cybersecurity O&M costs, subdivided into six categories which we shall discuss below. All costs are

RAMP-related. ORA has no recommended adjustments to SDG&E's forecast and other parties did not comment on this particular request.

28.3.1.1. Security Policy & Awareness

The Security, Policy, and Awareness group's primary function is on governance, compliance, and awareness of outreach aspects relating to the cybersecurity program. This group also provides security-oriented training and communication to all company employees, compliance with North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) reliability standards, and digital investigations. The forecast for this cost category is \$957,000.

We reviewed the forecast and find it reasonable and supported by the evidence. The activities performed by this group are necessary and we find the forecast methodology of using base year recorded, plus adjustments since costs are expected to be consistent from 2016. Parties did not object to SDG&E's forecast. The requested amount of \$957,000 is therefore authorized.

28.3.1.2. Director- Information Security

The Director of Information Security provides overall oversight of the cybersecurity program and projects and is responsible for cybersecurity at SDG&E, SoCalGas, and the Corporate Center. The requested amount for the Director is \$367,000 utilizing recorded base year costs plus adjustments.

We reviewed the requested amount for the Director of Information Security as well various testimony relating to cybersecurity including forecasts for O&M costs and capital projects aimed at mitigating and managing cybersecurity. We find the request to be reasonable and agree that the position is necessary in order to provide oversight to the cybersecurity program. We also agree with the forecast methodology used and note that no party objected to

either the request or forecast amount. We therefore conclude that this request should be authorized.

28.3.1.3. Information Security Programs

The Information Security Programs group is responsible for cybersecurity projects planning and strategy, management of vendors and maintenance budget, O&M contracts, projects portfolio management and requests for proposals. The forecast for this group is \$22,000.

We find the amount requested for this group to be minimal, reasonable, and supported by the evidence presented by SDG&E. We agree with the forecast methodology of using baseline costs plus adjustments because costs are expected to be consistent with base year levels.

28.3.1.4. Security Engineering

The forecast for the Security Engineering group \$1.434 million. This group's primary function is to support projects to secure systems and applications before they are placed in production. The group also implements, administers, and manages cybersecurity technology.

We reviewed the testimony and associated workpapers and find this group to be necessary in managing cybersecurity risks. The group's functions include risk assessment, access control, data security, information protection, maintenance, response planning, mitigation activities, and recovery planning. We find the forecast methodology of using base year recorded costs plus adjustments to be appropriate because costs for the TY are expected to be consistent with base year levels.

28.3.1.5. Security Operations

The forecast for Security Operations is \$1.757 million. This team manages the centralized log collection, is responsible for vulnerability discovery, incident

investigations and analysis, 24-hour cybersecurity monitoring, and is the first line of support for incident coordination and response.

We reviewed the testimony and supporting workpapers and find the request for this group to be reasonable and necessary. The group provides key support functions in maintaining and managing cybersecurity incidents and risks for the utility and customers. Labor costs reflected an increase due to the addition of one FTE because of the increase in the amount of activities. The forecast methodology of applying base year recorded, adjusted costs is appropriate because costs are expected to be consistent with base year levels.

28.3.1.6. Security Contracts

Security Contracts are non-labor expenses which include maintenance and licensing costs for capital projects, both planned and historical projects. The forecast for this cost category is \$3.370 million

Based on our review, we find that the requested expenses are necessary to continue to manage cybersecurity risks and to support new projects that will be undertaken in order to enhance and adapt existing capabilities to manage and respond to new and evolving threats. SDG&E applied a zero-based methodology to develop its forecast and we find this methodology to be reasonable because costs are in part based on new capital projects that will be supported. No party objected to the proposed costs related to this activity and we find that SDG&E provided sufficient evidence in order to substantiate the proposed costs. The proposed cost of \$3.370 million is therefore reasonable and should be adopted.

28.3.2. Capital

SDG&E is requesting \$6.146 million for 2017, \$7.232 million for 2018, and \$5.618 million for 2019 for cybersecurity capital projects. Other parties did not

comment or propose alternatives except for ORA which recommends using 2017 recorded capital expenditures as the basis for the amounts to be authorized. For 2017, ORA recommends \$1.631 million and proposes reducing the 2018 and 2019 amounts “based on an ordinary least squares time trend” resulting in \$1.815 million for 2018 and \$1.887 million for 2019.³⁵⁵ All costs for capital projects for 2017 to 2019 are RAMP-related.

Similar to our analysis of SoCalGas capital requests for cybersecurity, we find that it is more appropriate in this instance to examine each proposed project individually rather than to base three years of capital expenditures from recorded expenditures from a single year without examining the actual projects being proposed. Basing our review on capital expenditures for 2017 does not adequately capture increased efforts to manage cybersecurity risks pursuant to the RAMP process and nearly all of the proposed capital projects are RAMP-related projects.

And because there are many similarities among the proposed projects such as the forecast methodology and the basis for costs being the purchase of new hardware and software and associated labor costs, we shall again combine discussion of all projects to avoid repetitive discussion of similar topics such as those mentioned above.

28.3.2.1. Compliance Records Management

The forecast for this project is \$876,000 for 2017 using a zero-based forecast methodology. The project will implement a solution to comply with NERC recording and reporting requirements on CIP and system controls. Costs include

³⁵⁵ Exhibit 215 at 21.

purchase of new hardware and software and labor costs for design, implementation, integration with related systems, and testing for functionality.

28.3.2.2. Critical Infrastructure Protection

The forecast for this project is \$1.428 million in 2017, \$1.842 million in 2018, and \$2.270 million in 2019 using a zero-based forecast methodology. The project will implement multiple capabilities to prevent and detect cybersecurity events and will include some of the technologies developed by the California Energy Systems for the 21st Century Research & Development effort to protect critical infrastructure. The project will include access control, data security, maintenance, protective technology, analysis of anomalies and events, and continuous security monitoring. Costs include the purchase of new hardware and software as well as labor costs.

28.3.2.3. Smart Grid Substation Gateway Security Phase 2

The forecast for this project is \$1.068 million in 2017, \$1.332 million in 2018, and \$1.416 million in 2019 utilizing a zero-based forecast. The project aims to replace failing or insufficient gateway hardware by implementing network gateway devices to protect internet protocol networks the substation in order to securely perform configuration management remotely. The project includes the purchase of new hardware and labor costs to design, install, and integrate the gateways in electric distribution substations.

28.3.2.4. Network Anomaly Detection Phase 3

The forecast for this project is \$110,000 for 2017 using a zero-based forecast. The project will continue deployment to identified facilities of the network solution that provides additional levels of situational awareness in networks that have not been previously monitored. Network security

monitoring is a top active defense mechanism recommended by industry experts and includes the purchase of new hardware and software and labor costs.

**28.3.2.5. Electric Distribution Operations (EDO)
Network Security Architecture
Redesign**

The forecast for this project is \$772,000 for 2017 and another \$772,000 for 2018 using a zero-based forecast methodology. The project will upgrade the EDO network security architecture as part of SDG&E's efforts towards grid modernization. The enhancements will increase capabilities and support the implementation of new technologies. Costs are for new hardware and software purchases and labor costs.

**28.3.2.6. Active Directory Domain
Controllers for Distribution**

The forecast for this project is \$386,000 for 2017 and another \$386,000 for 2018 using a zero-based forecast. The project will implement Microsoft active directory domain controllers for the electric distribution control network. The implementation of this new technology is part of SDG&E's grid modernization efforts and part of the project will migrate the distribution management system and outage management system into the new active directory. The costs for the project include the purchase of new hardware and software as well as labor costs.

**28.3.2.7. Distribution Operations
Multifactor Authentication**

The forecast for this project is \$580,000 for 2017 and another \$580,000 for 2018 using a zero-based forecast. The project will implement multifactor authentication hardware and software for all electric distribution operations and will limit access to information and operations systems to authorized users.

Costs for the project include the purchase of new hardware and software and labor costs.

**28.3.2.8. Distribution Remote Thermal Unit (RTU)
Password and Configuration
Management**

The forecast for this project is \$387,000 in 2018 and \$386,000 in 2019 using a zero-based methodology. The project aims to implement centralized RTU password and configuration management for electric distribution substations. The access control capability limits access to authorized users. Costs for the project include the purchase of new hardware and software and labor costs.

28.3.2.9. Field Area Network Security

The forecast for this project is \$775,000 in 2018 and \$774,000 in 2019 using a zero-based forecast methodology. The purpose of the project is to implement additional field area network cybersecurity controls including the protection of information and data while at rest or in transit. The project will focus on protecting communications and control networks and managing the device network access. Costs include the purchase of new hardware and software and labor costs.

28.3.2.10. Privilege Access Management

The forecast for this project is \$772,000 in 2018 and another \$772,000 in 2019 using a zero-based forecast. The project will implement a hardware and software privilege access manager for electric distribution operations servers and field assets. The project limits access to information and operations systems to authorized users. Costs for the project include the purchase of new hardware and software and labor costs.

28.3.2.11. Distribution End Point Protection

The forecast for this project is \$926,000 for 2017 and \$386,000 for 2018 using a zero-based forecast methodology. The project will update end point protection on operator workstations and servers and supports the implementation of new technologies in the control network and field area networks related to grid modernization projects. The project includes the purchase of new hardware and software and labor costs.

28.3.2.12. Discussion

We have reviewed and analyzed the reasonableness of each capital project described above. We reviewed the evidence supporting each project such as the testimony of SDG&E's witness, the accompanying workpapers, applicable sections of the RAMP report, and arguments raised by SDG&E in its brief. Based on our analysis and review of each proposed project as well as the evidence submitted, we find all the capital projects to be necessary and the requested funding levels for each project reasonable except for the Privileged Access Management project.

Except for the Privileged Access Management project, we find that the evidence is sufficient to establish that the proposed projects are reasonable and necessary. SDG&E identified cybersecurity as one of its top risks and nearly all the projects are associated with SDG&E's enhanced efforts in mitigating, preventing, and managing cybersecurity risks using a risk-based framework for its GRC request. Many projects also promote grid modernization and the use of new technologies. Each of the approved projects focuses on an area of cybersecurity that SDG&E seeks to manage. We also agree with SDG&E that cybersecurity-related issues are now more complex, and the impact of attacks are potentially more damaging and larger in scope and we find it necessary to

update, upgrade, and expand SDG&E's ability to address and manage potential attacks and their impacts.

All the approved projects utilized a zero-based forecast methodology which we find appropriate because of the wide range of risk drivers which are more appropriately captured by identifying specific costs associated with each project. Many projects are also the result of an enhanced focus on mitigating cybersecurity risks which is being applied for the first time in this GRC pursuant to the RAMP process and these incremental efforts will not be captured as effectively using historical data.

With respect to the Privileged Access Management project, we find that this project has many overlaps with other projects being proposed such as the Distribution Operations Multifactor Authentication and Distribution RTU Password and Configuration Management as both of those projects also provide enhanced protections and mitigations aimed at limiting access to systems and operations to authorized users. SDG&E did not sufficiently distinguish the purpose and benefits this project will provide from other proposed projects with similar purposes. Thus, we are withholding authorization for this project and the associated funds requested which are \$772,000 in 2018 and another \$772,000 in 2019. If SDG&E disagrees and is able to address the concerns raised in this decision, then it can request authorization for the project in its next GRC. Before doing so, SDG&E should first evaluate the impact of the projects that were authorized in this GRC in order to determine whether the project will still be necessary.

29. Corporate Center – General Administration

Applicants' parent company, Sempra, formed a centralized Corporate Center that combines many shared services of SDG&E and SoCalGas and also

Sempra's other businesses which shall be referred to as Global. The Corporate Center provides corporate governance, policy direction, critical control functions, and other services that are performed more effectively from a centralized operation. A centralized operation for these services eliminates the need for additional staffing and other O&M costs.

This section discusses the cost allocation methodology applied in determining the percentage and amounts that correspond to services performed for SDG&E and SoCalGas. The portion that corresponds to services performed for Global as well as those retained by the Corporate Center are excluded from costs and requests made in the GRC. We shall also discuss the impact of RAMP and then analyze the different costs requested for the six groups of shared services under Corporate Center.

This section shall also address the IT Business Unit capital projects requested under this section.

29.1. RAMP

RAMP risks related to this section include Applicants' risk mitigation efforts associated with Records Management and Workplace Violence. Costs pertaining to RAMP are already included in the total O&M costs being requested so we shall only identify the RAMP costs in this subsection but shall discuss the reasonableness thereof as part of our analysis of the Corporate Center O&M costs that were forecast.

29.1.1. Records Management

Adherence to records management policies is vital to Applicants' operations. Accurate and complete records are necessary to avoid potential public safety, property, regulatory, and financial impacts. Records management includes identification, containment, organization, retention, and disposal of

records and documents. These activities were already being performed prior to the RAMP process and the incremental activities result in a \$2,000 increase being requested for SoCalGas and a \$4,000 decrease being requested at SDG&E as compared to the base year.

29.1.2. Workplace Violence

Mitigation for workplace violence consists of planning, awareness and incident management and includes programs that attempt to manage this risk before an event can occur. Mitigation efforts also include training of supervisors and employees to detect early signs of possible workplace violence. This activity was also already being performed prior to the process and total costs for TY2019 are forecast to increase by \$304,000 for SoCalGas and \$196,000 for SDG&E as compared to the base year.

29.2. Cost Allocation Methodology

Costs incurred by the Corporate Center for certain functions and services are fully charged out using direct assignment and allocation to SDG&E, SoCalGas, and Global. Costs that are not allocated to any of these three units are retained at the Corporate Center. Only costs that are directly charged or allocated to SDG&E and SoCalGas are included in the GRC applications and these costs are recorded in the appropriate accounts as defined by FERC. For TY2019, all Corporate Center expenses charged to SDG&E and SoCalGas are reflected in their respective A&G costs.

SDG&E and SoCalGas may also charge shared A&G costs among each other or to the Corporate Center for shared services that are located at each utility. These shared A&G costs are primarily rent, facilities management services, and some accounting services.

For allocation of costs, the Corporate Center's practice is to bill costs to business units by associating the costs as closely as possible to the level of service being provided to each business unit.³⁵⁶ Allocation of costs thus uses the following hierarchy: Direct Assignment; Causal/Beneficial; and Multi-Factor.

First, if an expense can be directly attributed to a business unit, then the expense is directly assigned to the business unit that incurred the expense. Second, if expenses support multiple business units, expenses are allocated using a causal/beneficial method which reflects the benefit received by each business unit. Finally, expenses that serve all business units without any causal relationship are allocated using a multi-factor method. For example, corporate oversight and governance functions support Sempra companies as a whole. These expenses weigh four factors: revenues; operating expenses; gross plant assets and investment; and full-time employees or equivalents in order to determine the proper allocation of expenses. The four factors used in the multi-factor method are compiled at the beginning of each year using data from the prior year as the basis for actual allocations in the following year.

Parties do not object to the general cost allocation methodology utilized by Applicants except for TURN which states that the multi-factor basic allocation rates should not be trended as the trend line analysis has previously been proven wrong. We reviewed Applicants' proposed allocation methodology and find that the methodology is consistent with Commission decisions in Applicants' TY2012 and TY2016 GRCs.³⁵⁷ However, specific objections and

³⁵⁶ Exhibit 315 at MLD-11.

³⁵⁷ D.13-15-010 and D.16-06-054 respectively.

recommendations by parties as to the actual allocation and corresponding costs to each of the shared services under this section are reviewed as we discuss each shared service. We address the issue raised by TURN in a later section of this topic.

Forecasted multi-factor allocation rates for 2018 and 2019 were arrived at using a trend forecasting method based on historical data from 2013 to 2016 and applying a standard inflation increase to most items except for non-standard items such as those having contractual increases. The resulting forecast for TY2019 is a 72.6 percent allocation of costs to Applicants.³⁵⁸ We find this forecast to be consistent with historical allocations in 2013 to 2016 which ranged from 76.1 percent to 76.9 percent and with the cost allocation for 2017 which is 76 percent.

Parties did not raise any concerns and we also found no issues in the calculation of specific allocations to SDG&E and SoCalGas and so we only discuss allocations as it applies to both utilities combined.

29.3. Shared Services

29.3.1. Finance

The Finance division is responsible for maintaining the financial integrity of Sempra and its companies and for raising and managing capital. The projected expense for TY2019 for the Finance division is \$59.556 million of which \$28.571 is allocated to SDG&E and SoCalGas. The Finance division is further subdivided into seven categories and the table below shows the TY2019 forecast

³⁵⁸ This figure was originally 76.2 but Applicants presented a calculation that included the impact of the Oncor acquisition as shown in Exhibit 317 Table MLD-3A showing the allocation for TY2019 as 72.6 percent (33.3 percent for SDG&E and 39.3 percent for SoCalGas).

costs for the Corporate Center and the corresponding allocations for Applicants for each of these seven categories. Following the table is a discussion of the functions of each of these seven categories.

Finance	Corporate Center TY2019 Forecast	Utility Allocation
Chief Financial Officer	\$970,000	\$607,000
Accounting Services	\$9,180,000	\$5,530,000
Tax Services	\$11,603,000	\$6,750,000
Treasury	\$24,554,000	\$7,737,000
Investor Relations	\$2,214,000	\$1,691,000
Internal Audit & Risk Management	\$9,622,000	\$5,457,000
Financial Leadership Program	\$1,414,000	\$799,000
Total	\$59,556,000	\$28,571,000

Chief Financial Officer

The Chief Financial Officer (CFO) is responsible for Sempra's operating and capital budgets and development of financial goals. The CFO also oversees the functions of various financial units and divisions such as Treasury, Tax Services, Investor Relations, Internal Audit, etc. The CFO also provides financial reports to the Board and maintains relationships with financial institutions and the financial community. Allocation for the CFO used a weighted average of the allocation methodologies used by each department reporting to the CFO.

Accounting Services

Accounting Services include the Controller, Assistant Controller, Accounting Research and Policies, Strategic Planning, Corporate and Global Accounting, and Financial Reporting. All non-direct costs for accounting services were allocated using a multi-factor basic method except for Strategic Planning and Corporate and Global Accounting because of the additional reliance by Global. These two groups were allocated using a multi-factor

variation that equally divided the overall allocation between Applicants and Global.

Tax Services

The Tax Services department is responsible for federal, state, local, and international tax compliance and planning as well as tax accounting, regulatory tax research, and establishing tax policy governance. Allocation for the vice president of this department used a causal/beneficial allocation method using an average based on the annual time estimates from every staff member.

Treasury

Treasury is responsible for corporate finance, working management, pension and investments, project finance, business planning and project controls, and corporate development which include mergers and acquisitions. Various allocation methods were utilized based on the service provided. Fees for short-term and long-term financing are directly assigned to the business units for which the loans were contracted. For the treasury group, the overall activity level and projects requiring financing were estimated and assigned. For the pension and investments group, the causal/beneficial method was used based on the value of each utility's pension funds. The causal beneficial method was also used for business planning and project controls based on the percentage of labor hours that were used. The multi-factor method was utilized for cash management services as the services provided by this group benefits all business units. Finally, for the Treasury vice president, a weighted average of all units that report to the vice president was utilized in allocating costs.

Investor Relations

Investor Relations facilitates the flow of information and dialogue with investors. The department maintains communications with securities analysts,

shareholders, and the financial community through various means. Costs are allocated using the Multi-Factor Basic method as the activities of this department benefits all business units.

Internal Audit and Risk Management

The Internal Audit and Risk Management department is responsible for internal audits, Sarbanes-Oxley Act (SOX) compliance, risk management, and insurance and risk advisory. These services are centralized for all of Sempra's business units. Allocation of costs for the vice president for this department is based on the weighted average of the annual budget for departments that report to the vice president. On the other hand, allocation of costs for the audit services group is based on Sempra's annual audit plan but excludes hours used to serve entities in Mexico and South America. Finally, allocation of costs for SOX compliance is based on an annual time study of the weighted average of the workload of each employee in the group and Corporate Center hours reallocated using the Multi-Factor Basic method.

Financial Leadership Program

The Financial Leadership Program is an important program in which Sempra attracts and develops accounting and finance staff using a multi-year rotation plan that includes giving exposure to new recruits. Allocations were based on a weighted average of the employees in the program based on the business units they support.

29.3.1.1. Positions of Intervenors

ORA recommends \$9.178 million for Internal Audit and Risk Management with an allocation of \$5.013 for Applicants by applying a three-year average of historical costs from 2014 to 2016 net of costs associated with attorney-client privilege audits during those three years.

29.3.1.2. Discussion

We have reviewed the different groups that comprise the Finance division and examined the forecast amounts for each group, the allocation methodology used to allocate costs, and the resulting amount to be allocated to Applicants. We find that the testimony submitted reasonably supports the request and adequately sets forth the functions and necessity of the Finance division as well as the seven subgroups that comprise it. We evaluated each of the allocation methods that were utilized and find them to be appropriate. The methods used follow the hierarchy of allocation methods discussed at the beginning of this section. Many of the services and functions are centralized and benefit all business units for which the multi-factor allocation method was properly utilized.

Parties for the most part did not challenge the total costs that were forecast for the Corporate Center as well as the allocation method used, and the resulting amount to be allocated to Applicants except for ORA's objection to the amounts allotted for the Internal Audit and Risk Management group. However, we reviewed ORA's recommendation and find that the basis for its proposal is the exclusion of the cost for 20 audits conducted to which ORA was not granted access. However, Applicants explained that access to the documents pertaining to these audits was withheld from ORA because the documents were considered to be confidential in nature because of the attorney-client privilege. We find Applicants' explanation to be reasonable and agree that these audits were legitimate expenses for necessary audits and should be included in costs for the Internal Audit and Risk Management group. We therefore accept Applicants proposed Corporate Center and allocated costs.

Based on the above, we find the TY2019 forecast of \$59.556 million for the Corporate Center to be reasonable and conclude that the allocated amount to Applicants of \$28.571 million should be authorized. Costs for the Finance division decreased overall by approximately \$3.6 million compared to the base year due to savings from FOF staffing and procurement savings which more than offset higher costs for consulting, labor, IT, travel, training, and recruitment.

29.3.2. Legal, Compliance, and Governance

This division provides legal, compliance, and governance services to all Sempra companies and coordinates the retention and oversight of outside law firms, including the negotiation of outside legal fee arrangements.³⁵⁹ The division is subdivided three categories and the table below shows the TY2019 forecast costs for the Corporate Center and the corresponding allocations for Applicants.

Legal, Compliance, and Governance	Corporate Center TY2019 Forecast	Utility Allocation
Legal Services	\$51,228,000	\$18,163,000
Compliance and Governance	\$7,036,000	\$5,365,000
Executive	\$4,079,000	\$0
Total	\$62,344,000	\$23,528,000

Legal Services

Legal Services provides services in the areas of litigation, labor and employment law, environmental law, commercial law, corporate law, real estate, mergers and acquisitions, financing, and securities matters. Under the General Counsel, the Corporate Center Law Division comprised of attorneys and legal staff provides legal expertise in areas of law not covered by lawyers operating in

³⁵⁹ Exhibit 315 at MLD-31.

individual business units reducing the need to hire outside legal counsel. The Law Division also coordinates the retention and oversight of outside law firms for all business units. Costs are mostly allocated by direct assignment. For costs that are not directly assigned such as costs for support staff, supplies, and maintenance of the law library, these costs are allocated based on a ratio of time spent on matters for each business unit. Costs for the General Counsel and Executive Vice President are allocated using a weighted average of the allocation methodologies used by each department within the Legal, Compliance, and Governance division.

Compliance and Governance

The Compliance and Governance department provides leadership and partners with staff in providing business conduct programs and emergency preparedness. Business conduct programs include management and oversight of compliance risk assessment, development and maintenance of business conduct guidelines for employees, compliance and ethics, and other related programs. Emergency preparedness includes emergency training, safety performance tracking, oversight of the crisis management center, emergency drills, and other related programs. Costs for compliance assessments and specific programs are directly assigned to applicable business units and those that cannot be assigned and benefit all units are allocated using the multi-factor basic method.

Executive

The Executive department includes the Chairman, President, and CEO of Sempra, and the Sempra Group Presidents. All costs pertaining to these high-level executives are retained at the Corporate Center and are not distributed or allocated to Applicants.

29.3.3. Human Resources and Administration

The Human Resources and Administration division develops corporate-wide policies, programs, and procedures that apply to the entire workforce of the Sempra companies. The division also oversees IT activities, corporate systems, physical and cybersecurity, and provides services that are not provided by Sempra's subsidiaries. This division is subdivided into four groups and the table below shows the total forecast for the Corporate Center for TY2019 as well as the allocated costs to Applicants and the breakdown of costs for each of the four subgroups comprising the division.

Human Resources and Administration	Corporate Center TY2019 Forecast	Utility Allocation
Senior VP Chief	\$1,512,000	\$1,301,000
Compensation & Benefits	\$5,116,000	\$4,487,000
Corporate Human Resources Staffing and Development	\$1,738,000	\$1,318,000
CIO, Corporate Systems, and Security	\$16,331,000	\$14,594,000
Total	\$24,698,000	\$21,700,000

Senior VP Chief Human Resources and Administration

The Senior VP Chief Human Resources and Administration provides strategic direction and overall corporate guidance in several areas such as compensation and benefits, Human Resources (HR) information systems, diversity programs, workforce planning, leadership development, compliance training, and security. Costs are allocated using a weighted average of the diverse allocation methodologies used by each department within the division.

Compensation and Benefits

The Compensation and Benefits department administers employee compensation and benefit programs. This area includes compensation and benefits plan design, contract negotiations, vendor management, cost control,

human resources accounting, and payroll services. Costs for this department are mostly allocated reflecting the level of service provided to business units based on the number employees in the business unit. For executive compensation, costs are allocated using a weighted average of executive FTEs and director-level FTEs at all business units.

Corporate Human Resources and Staffing Development

Corporate Human Resources and Staffing Development functions take care of daily employee relations, staffing, and recruiting for the Corporate Center and provide human resources advisory and support services to all Corporate Center functions that provide shared services to SDG&E and SoCalGas.³⁶⁰ This department also provides HR policy interpretation, performance management, employee discipline, career counseling, salary administration, and processes termination of employees. Costs are allocated using the multi-factor basic method because services are provided to all areas of the Corporate Center which in turn serves all Sempra companies.

CIO, Corporate Systems, and Security

The Chief Information Officer (CIO), Corporate Systems, and Security department develops and manages the policies and programs for security systems, security investigations, workplace violence avoidance, and crisis and security risk management services. This department also provides HR and payroll system support and maintains employee databases. Security related costs are generally allocated using the causal-beneficial method while security related services specific to senior executives are allocated based on estimated

³⁶⁰ Exhibit 315 at MLD-45.

usage with 25 percent being allocated to Applicants. Costs for maintenance of employee databases and related services are allocated based on the number of employee records of each business unit and costs for the office of the CIO are allocated based on the level of service provided to business units.

29.3.3.1. Positions of Intervenors

ORA recommends an approximately \$95,000 reduction to Applicants' forecast amount for the CIO, Corporate Systems, and Security department based on its opposition to the request for one new position in the department. ORA states that Applicants failed to justify the need for this position and that this new position will not benefit ratepayers.

29.3.3.2. Discussion

In their rebuttal testimony, Applicants provide additional explanation regarding the new position to which ORA is objecting to. Applicants explain that the new position will be needed to assist with the MyInfo Human Resources online learning and certification programs.³⁶¹ We considered ORA's position and the additional information provided by Applicants and find that there is sufficient justification to support the request for the new position. Applicants also provided that the new position is necessary because of additional learning and certification programs that will have to be managed and additional data from these new programs that will have to be processed. We also find that the new position will benefit ratepayers although not directly since the direct benefit is to the Corporate Center which in turn provides services to Applicants. Therefore, we find the Corporate Center forecast and allocated costs for the CIO,

³⁶¹ Exhibit 317 at MLD-11.

Corporate Systems, and Security department of \$14.594 million to be reasonable and should be approved.

We also find the forecast and allocation amounts for the Senior VP Chief Human Resources and Administration, Compensation & Benefits, and Corporate Human Resources Staffing and Development departments to be reasonable and supported by the evidence. Applicants provided sufficient testimony to support the forecast amounts for these departments. The testimony described the different functions of each department and the cost drivers which led to the forecast for this division. Applicants also adequately explained either the assignment or allocation of costs which is consistent with the methodology described in Section 29.2 of the decision. Parties do not object or did not provide a position with regards to the forecast and allocation amounts for these departments.

In view of the above, we find that the requested amount of \$21.700 million to be allocated to Applicants for the Human Resources and Administration division should be approved. This amount is approximately \$6.3 million higher than base year levels because of higher payroll processing fees and higher consulting and labor contract fees related to the implementation of the new human capital management system.

29.3.4. Corporate Strategy and External Affairs

This division provides overall policy guidance for interactions with external constituents to ensure compliance with laws and regulations, and to meet business objectives. Some of the functions provided by this division stem from the fact that Sempra companies conduct business in multiple communities and states and sometimes other countries. This division has seven subsections

and the table below shows the total TY2019 Corporate Center forecast for each section and the corresponding allocations for Applicants that are being proposed.

Corporate Strategy and External Affairs	Corporate Center TY2019 Forecast	Utility Allocation
Executive VP	\$799,000	\$351,000
Corporate Strategy	\$606,000	\$462,000
Communications	\$2,205,000	\$1,501,000
Issues Management	\$1,139,000	\$544,000
Corporate Responsibility	\$1,068,000	\$626,000
Government Affairs	\$3,388,000	\$130,000
Employee Programs	\$5,214,000	\$276,000
Total	\$14,420,000	\$3,890,000

Executive VP

The Executive VP of this division oversees the entire division which provides corporate communications, issues management, corporate responsibility, and governmental affairs. Allocation for the Executive VP is based on a weighted average of the allocation methodologies used by each department reporting to the Executive VP.

Corporate Strategy

Corporate Strategy is responsible for facilitating and providing content for the annual strategy report of the Board of Directors. This department also conducts research and analysis for business units and in support of senior management decision making. The department also reviews and provides research and analytical support to submissions by business units to the annual strategy review. Costs are allocated using the multi-factor basic method because the activities of this division are primarily in support of all business units.

Communications

The Communications department oversees most of the shareholder communications including earnings announcements and media-related activities.

Communication usually involves critical information to investors and customers regarding the financial health and business strategy of the company and individual business units. The department is also involved in communications with business unit customers and the communities in which the business units operate, and communications through the internet concerning brand, identity, image, and public information. Allocation of costs for this department uses the multi-factor basic method for the annual report and external communication because these functions serve all business units. For other services, the multi-factor split method is used where 50 percent is allocated to Applicants because these types of services are provided on behalf of Applicants, Global, or the Corporate Center.

Issues Management

The Issues Management department identifies, analyzes, and reports on key external issues and trends that may impact Sempra. The department also provides analysis, input, and resources to external plans for key projects by business units. Allocation for this department uses the multi-factor basic method because all business units are served. However, costs for the Regional Vice President & Director were retained at the Corporate Office because the work performed by this position is not utility-related.

Corporate Responsibility

Corporate Responsibility supports the goal setting, tracking, and monitoring of corporate responsibility objectives. The department also collects data, including surveys and data requests, for corporate responsibility reporting. The department also manages the corporate political contributions budget. Costs are allocated using the multi-factor basic method but costs directly related to

Political Action Committee and political reporting are excluded from allocation and retained at the Corporate Center.

Governmental Affairs

Governmental Affairs manages federal legislation and advocacy and represents Sempra business units on all federal legislative issues that may impact the Sempra companies. This department includes the FERC Relations department and conducts lobbying activities. Costs relating to lobbying activities are retained at the Corporate Center while activities by the FERC Relations department are allocated using the multi-factor split method which evenly divides costs between Applicants and Global at 50 percent each.

Employee Programs

The Employee Programs group manages corporate policies and programs for charitable contributions and also corporate memberships. This group also manages corporate involvement in business associations and non-profit associations and the Sempra Energy Foundation which funds a variety of employee programs. Costs are allocated based on the number of employees at each business unit because the programs managed by this group apply to all employees of all business groups.

29.3.4.1. Discussion

Based on our review, we find the forecasts under this division to be reasonable and supported by the evidence. Applicants provided adequate information regarding the functions, activities, and programs under this division and the forecast costs for the Corporate Center. We found the various allocation methodologies to be appropriate and note that Applicants correctly excluded certain costs that pertain to positions and activities that only affect and benefit the Corporate Center. Many of these excluded costs are in the Governmental

Affairs and Employee Programs groups and these costs were retained at the Corporate Center. The allocation methods used for executive positions were consistent with the allocation methodology used for other executive positions in other divisions. ORA did not object to the forecast of corporate costs and other parties did not provide any comments. Therefore, we find that the requested amount of \$3.890 million representing the costs allocated to Applicants should be approved.

29.3.5. Facilities and Assets

Expenses relating to facilities and assets are grouped into three main categories and the table below shows the three groups of expenses, the total TY2019 forecast for the expenses, and the allocated amounts to Applicants.

Facilities and Assets	Corporate Center TY2019 Forecast	Utility Allocation
Depreciation / Rate of Return	\$13,340,000	\$8,340,000
Property Taxes	\$2,946,000	\$1,462,000
Facilities/Other Assets	\$13,640,000	\$6,085,000
Total	\$29,926,000	\$15,886,000

Depreciation/Rate of Return

Corporate Center assets are primarily made up of the Sempra headquarters, building leasehold improvements, building furniture, office equipment, IT equipment, application software, and information systems hardware and software.

These assets are depreciated based on the asset class and expected life utilizing a straight-line method of computing depreciation. Depreciation expense is then derived from this calculation. Sempra is in the process of placing into service additional assets in 2017 and 2018 such as the replacement for the MyInfo Human Resources system, the new project analysis and reporting system and new computer equipment for all personnel. These new assets are valued at

approximately \$15.6 million and depreciation expense for these assets is included in the calculation for TY2019.

Also, an asset carrying charge or rate of return is calculated for the assets to allow a return on the assets. Using an asset's net book value which is the total acquisition cost less total accumulated depreciation, the rate of return is calculated by applying the asset carrying charge rate³⁶² to the average monthly asset balance less associated deferred income taxes. This rate of return is then allocated to Sempra and its business units.

Allocation for the Sempra headquarters, building leasehold improvements, furniture, and equipment are calculated based on direct occupancy of the various facilities. Hardware and software assets are allocated using direct allocation for some assets and for others such as the MyInfo system, based on the number of users. Expenses for vehicles, miscellaneous assets and other assets used by Corporate Center employees are retained at the Corporate Center and not allocated to Applicants.

Property Taxes

Taxes paid by the Corporate Center only for property owned by Sempra which generally includes the Sempra headquarters and leasehold improvements. Taxes for the headquarters are allocated using the multi-factor basic method while taxes for leasehold improvements are allocated based on business unit occupancy.

³⁶² The asset carrying charge is based on the rates of return for SDG&E and SoCalGas which are 7.55 percent and 7.34 percent respectively.

Facilities and Other Assets

Various cost centers such as rent expense, corporate IT help desk and fractional ownership in corporate aircraft. Allocation for most of these assets are based on business unit use or occupancy while expenses for the IT help desk are allocated using the multi-factor basic method because the help desk benefits all business units.

29.3.5.1. Discussion

We reviewed the testimony, workpapers and Applicants' briefs regarding this section and find that the allocation methods and rationale for them are adequately detailed. The forecast for depreciation and taxes are mechanically calculated based on actual net book values of assets and the expense for rate of return uses the authorized rates of return for SDG&E and SoCalGas. We find the various allocation methodologies applied to be appropriate and consistent with the general allocation methodology described in Section 29.2 of this decision. ORA does not oppose the forecast for this section and other parties did not comment on Applicants' proposal.

Therefore, we find the requested amount of \$15.886 million representing the allocated costs for Facilities and Assets to be reasonable and they should be approved. Costs increased by around \$3.3 million compared to the base year due to higher depreciation expense because of the planned addition of around \$15.6 million of new assets and the resulting rate of return for these new assets.

29.3.6. Pension and Benefits

Pension and Benefits costs for the Corporate Center are excluded from labor costs appearing in the first five divisions discussed in this section of the decision (Finance, Legal, Compliance, and Governance, etc.) and are instead consolidated in this subsection of Corporate Center – General Administration

costs. Costs are subdivided into five groups and the table below shows the TY2019 forecast for the Corporate Center and the allocated amounts to Applicants. Pension and benefit costs are considered as labor overheads and the allocation of costs follow the allocation of the original labor dollars to which they are added to.

Pension & Benefits	Corporate Center TY2019 Forecast	Utility Allocation
Employee Benefits	\$13,347,000	\$8,438,000
Payroll Taxes	\$5,517,000	\$3,496,000
Incentive Compensation	\$19,782,000	\$11,325,000
Long-Term Incentives	\$42,303,000	\$8,757,000
Supplemental Retirement	\$13,100,000	\$3,394,000
Total	\$94,048,000	\$35,409,000

Employee Benefits

All health and welfare plans available to Corporate Center employees. Primary benefits include pension, medical, dental, disability, life insurance, and retirement savings plan as well as other post-retirement benefit costs.

Payroll Taxes

Taxes imposed on employers. The forecast rate for TY2019 is 3.46 percent of direct labor costs.

Incentive Compensation

Costs for the portion of an employee's compensation that is at-risk. Variable pay plans have been part of Sempra's total compensation strategy aimed at motivating employees to meet or exceed important financial and project completion goals. The variable pay plans are commonly referred to as Incentive Compensation Plans.

Long-Term Incentives

Granted under the Sempra Long-Term Incentive Plan in the form of performance-based restrictive stock units and service-based restricted stock units.

Supplemental Retirement

Represent the forecast for projected benefit accruals for executives eligible for these benefits by 2019.

29.3.6.1. Positions of Intervenors

ORA recommends approving 93.1 percent, of Applicants' request for Employee Benefits, 41.76 percent of the request for Incentive Compensation, and zero dollars for both Long-Term Incentives and Supplemental Retirement. ORA has no objections to the requested amount for Payroll Taxes.

29.3.6.2. Discussion

First, we find the allocation method utilized by Applicants, following the allocation method used for the labor dollars to which the pensions and benefits are attached to, is appropriate in this case. Parties also have no objections to this allocation method. Next, we agree with the forecast and allocated costs for Payroll Taxes as the forecast costs are mostly calculated from projected labor costs. We also agree with Applicants' proposed forecasts and allocation amounts for Employee Benefits and Incentive Compensation.

For Long-Term Incentive costs, we first examined whether ratepayers or shareholders benefit from this compensation program and looked at how the Commission treated such costs in the past. The awards are stock based which means that the value of the stock units will grow if the company's stock price increases. Because the company's stock is tied to the company's financial performance over a period of time, we find that a premium is being placed on

the companies' financial performance. Thus, awardees of stock units have an incentive to align with Sempra's goals that improve the company's financial standing and on other issues that raise the stock price. These factors lead us to conclude that the long-term incentive awards benefit shareholders rather than ratepayers although there is some benefit to ratepayers in terms of attracting and retaining employees who are experienced and high performing. With regard to the Commission's past treatment of long-term compensation, our review of the decisions show that the Commission has generally disallowed long-term incentive compensation. Based on all the above, we find that the Long-Term Incentive costs being requested here primarily benefit shareholders and therefore find it reasonable to deny Applicants' request.

For Supplemental Retirement costs, we find that only 50 percent of the request should be approved because long-term incentive programs and post-retirement benefits benefit shareholders as well as ratepayers and so both shareholders and ratepayers should share in the costs for these equally.

As a result of the above discussions, Applicants' requested allocation amount of \$35.409 million should be reduced by \$10.454 million to account for disapproval costs Long-Term Incentives and 50 percent of costs for Post-Retirement benefits. Therefore \$24.955 million should be authorized for Pension and Benefits.

29.4. Oncor Transaction

On March 9, 2018, Sempra completed a transaction that resulted in Sempra acquiring an 80.25 percent interest in Oncor Electric Delivery Company, LLC (Oncor).

ORA asserts that because of the acquisition of Oncor, forecast costs for Corporate Center - General Administration should also be allocated to Oncor.

From its latest Form 10-K filing with the Securities and Exchange Commission, Oncor's total assets are \$13.470 billion which when added to Sempra's assets would comprise around 25 percent of the total assets including Oncor.

Subtracting the acquisition cost of \$9.45 billion, Oncor comprises around 22.8 percent of the total utility assets under Sempra. ORA therefore recommends that Corporate Center costs be allocated to Oncor at a 22.8 percent factor. ORA's recommendation results in an allocated total of \$84.351 million to Applicants which is inclusive of all of its other proposed reductions for this section. ORA's recommended total without taking Oncor into consideration is \$109.265 million compared to Applicants' allocated total of \$129.129 million.

Applicants, however, state that Oncor operates independently from Sempra and has its own employees that perform the shared services and functions performed by the Corporate Center for Sempra business units. Applicants add that as a result of this independence, there is very limited sharing of any operational and financial resources and so Oncor is not included in allocation calculation for Corporate Center - General Administration costs.

29.4.1. Discussion

A close look at the Oncor transaction shows that after the series of mergers which were part of related transactions, Sempra, through Sempra Texas Utility and Sempra Texas Intermediate Holding Company, LLC, acquired 100 percent ownership of Oncor Electric Delivery Holdings Company, LLC (Oncor Holdings), a holding company that owns an 80.25 percent interest in Oncor. The remaining 19.75 percent interest is owned by another company, Texas Transmission Investment, LLC. The resulting corporate structure shows that Sempra does not have direct control of Oncor.

Applicants also provided testimony which states that the Oncor Transaction “contain existing governance mechanisms and restrictions around Oncor Holdings and Oncor that limit Sempra’s ability to direct the management, policies and operations of Oncor Holdings and Oncor, including the deployment or disposition of their assets, declaration of dividends, strategic planning and other important corporate issues and actions.” The restrictive provisions also limit the number of Sempra representation in Oncor’s and Oncor Holdings’ Board of Directors such that a majority of Board members are independent directors.

We find that the mechanisms described above support Applicants’ contention that there is limited sharing of operational and financial resources between Sempra and Oncor and that Oncor is operated independently from Sempra unlike other business units directly controlled by Sempra such as Applicants. Applicants are also obligated under Rule 1.1 of the Commission’s Rules not to make false statements or risk facing severe sanctions for violation thereof. Applicants also explain that Oncor has its own finance, accounting and human resources units. From all the foregoing, we find that most of the shared services provided by the Corporate Center are not provided directly to Oncor.

However, we do find, and Applicants agree that, there are some services performed by the Corporate Center that inure to the benefit of Oncor such as corporate oversight activities and other activities such as information and benefits obtained from activities by the investor relations group or external affairs. Because Oncor benefits from these activities that are being performed for the benefit of all Sempra business units, we find that it is only fair to require that Oncor share in the costs of these activities. Thus, we find it reasonable to have

Applicants update their TY2019 forecast to include Oncor in the allocation of such benefits.

Because activities and services are not performed by the Corporate Center for Oncor directly, we do not expect there to be costs that will be allocated to Oncor by direct assignment or by the causal/beneficial method as the benefits to Oncor are more indirect in nature. Instead, we find that Oncor should only be part of costs involving the multi-factor allocation method.

We reviewed ORA's calculation and agree with Applicants that ORA's calculation is not consistent with the multi-factor method because it only included the assets of SDG&E, SoCalGas, and the Oncor acquisition cost. We find that it is more appropriate to include all of the assets of Sempra and its other business units as well as the assets of SDG&E, SoCalGas and the Oncor acquisition price as the basis for determining the allocation of costs using the multi-factor method.

Applicants presented a calculation which added the \$9.566 billion Oncor acquisition price to the total Gross Plant Assets and Investments of Sempra and all its business units. Applying the multi-factor method using the above total results in a \$2.4 million reduction to Applicants' requested allocation costs. We find the above methodology and calculation to be reasonable except that the reduction should only be by \$2.219 million to account for the fact that we only approved around 70.47 percent of the requested amount for Pension and Benefits. Thus, the deduction calculated from Pension and Benefits of \$614,000 should instead be 70.47 percent of that amount or approximately \$432,686.

In conclusion, the amounts authorized for Corporate Center - General Administration as discussed in Section 29.3 of this decision should be reduced by \$2.219 million to account for the Oncor Transaction.

29.4.2. TURN's Proposed Forecast

As stated earlier in this section, TURN recommends that the multi-factor basic rates should not be trended as this trend analysis has previously been proven to be wrong. Instead, TURN recommends that the forecast for the TY2019 multi-factor basic allocation add the Oncor acquisition cost and then remove the 2019 assets related to SONGS and Aliso Canyon. After the above adjustments, TURN recommends lower multi-factor adjustments for SDG&E and SoCalGas by 1.46 percent and 1.96 percent respectively and a higher multi-factor rate for unregulated activities by 3.42 percent. Because of the complexity of the calculations, TURN is unable to calculate the exact figures but expects the result to be several million dollars less than what Applicants are requesting.

TURN's recommendation to include the Oncor acquisition cost into the multi-factor calculation is being adopted as discussed in the preceding subsection. However, according to Applicants' estimate as shown in the rebuttal testimony of witness Demontigny,³⁶³ subtracting the amounts remaining for SONGS consisting of a \$152 million receivable from Edison and Aliso Canyon consisting of a \$606 million long-term insurance recovery receivable, will have minimal impact on the total gross plant assets and investments. Applicants' testimony calculates the impact to be 0.1 percent. Thus, we find it unnecessary to change the methodology adopted by Applicants for calculating multi-factor allocations and using data from the prior year as the basis for allocations in the following year. In any case, TURN's expectation that the amount authorized would be several million dollars less than what Applicants are requesting is

³⁶³ Exhibit 317 at MLD-11 to 12.

already being met by the addition of the Oncor acquisition into the multi-factor calculation which results in \$2.296 million less than the amount that would have been authorized if the Oncor transaction was not included into the calculation.

29.5. IT Business Unit Capital Projects

SoCalGas is also requesting \$2.404 million in 2017 and \$0.427 million in 2018 for an IT-related capital project which will install a cloud-based system which aims to improve access-related issues. The project will also reduce security and audit risks. We reviewed the proposed project and find SoCalGas' request to be reasonable and supported by the evidence presented. Parties do not oppose SoCalGas' request and we find that the proposed project should be approved.

29.6. Update Filing

SoCalGas' update testimony in Exhibit 514 revised the escalation factor applied to Corporate Center labor and non-labor costs. The updates are part of the rate case plan and reflect updated data indexes relied on in making the forecasts. The escalation for non-labor was updated from 1.0534 to 1.0648 and while the escalation for labor was adjusted from 1.0849 to 1.0869. The above updates result in minimal changes to the Corporate Center forecasts being adopted in this section and the escalated amounts will only be reflected in the RO model.

30. Corporate Center – Insurance

This section discusses the O&M costs associated with Corporate Center - Insurance. As with Corporate Center - General Administration, operation for these services is centralized and costs are allocated to the different Sempra business units including SDG&E and SoCalGas. Only costs allocated to SDG&E and SoCalGas are included in these GRCs.

30.1. Cost Allocation

Insurance premiums are proposed to be billed in accordance with the following cost allocation priorities: (a) direct assignment; (b) causal/beneficial; (c) multi-factor basic; and multi-factor split.³⁶⁴

First, insurance premium expenses that can be directly attributed to a business unit are directly allocated to that business unit such as insurance for specific projects. Next, when insurance coverage is provided to multiple business units under a single policy, the causal/beneficial method is used. This typically occurs when the primary driver for the insurance is a single key risk factor. For example, fire insurance is to be allocated based on overhead transmission and distribution miles in proportion to the total cost of the insurance premiums. Finally, costs for insurance policies that provide coverage for a broad spectrum of risks that cannot be allocated by a single factor are allocated using the multi-factor method.

Several parties object to the various forecast amounts but raise no issues with respect to the proper allocation of costs as between SoCalGas and SDG&E. Thus, we discuss in this section the total allocations made for both utilities combined, except in cases where an issue pertains to one of the utilities only.

30.2. Shared Services

Insurance needs are grouped into three general categories which are property insurance, liability insurance, and surety bonds.

³⁶⁴ Exhibit 238 at NKC-1 to 2.

30.2.1. Property Insurance

Property insurance is for coverage for losses or damage to assets of Sempra and its business units. The table below shows the different classes of property insurance, the TY2019 forecast for the Corporate Center, and the allocated amounts for SDG&E and SoCalGas. A forecast was developed for each individual type of insurance policy relying mostly on forecasts by Sempra's primary insurance broker.

Property Insurance	Corporate Center TY2019 Forecast	Utility Allocation
Primary Property	\$9,157,000	\$6,409,000
Excess Property	\$10,194,000	\$8,908,000
Other Property	\$953,000	\$759,000
Total	\$20,304,000	\$16,076,000

Primary Property

Insurance provides coverage for direct physical damage to property owned by Sempra and its business units. Machinery breakdowns, earthquake, flood, and terrorism are covered perils although electric and gas distribution transmission lines are excluded here. Business interruption is also excluded for Applicants although included for Sempra's other business units. Costs are to be allocated based on risk-adjusted rates applied to replacement value of property for each business unit.

Excess Property

Insurance supplements primary property insurance and is used when property is valued more than what the primary property insurance states. This increases the policy's limits and insures that the property is properly covered from financial risks. Costs are to be allocated based on reported asset values that cover Sempra business units benefitting from the insurance.

Other Property

Insurance includes coverage for gas storage wells for well-control incidents, crime insurance, insurance for the Arizona Public Service Corporation (APS) Yuma 500 kV Transmission System, and for included SONGS property. Costs for gas storage well insurance are primarily allocated to SoCalGas and partially to other business units with storage facilities. Costs for crime coverage are allocated using the multi-factor basic method. Costs for SDG&E's share of insurance premiums for the APS Yuma 500 kV Transmission System which is jointly owned by SDG&E and APS, are allocated to SDG&E. Lastly, costs for the existing SONGS switchyard which will be used after decommissioning is procured by SCE which bills SDG&E for its share. The majority of other SONGS expenses are excluded from the GRC.

30.2.1.1. Position of Intervenors

CFC recommends around a \$1.78 million reduction to the allocated cost for Excess Property insurance.³⁶⁵ CFC states that the Experience Modification Factor (EMF) used to adjust the insurance premium increased from 1.0 to 1.25 in 2016 because of the Aliso Canyon incident in 2015 and that the Commission directed in D.16-06-054 that costs relating to the Aliso Canyon leak be excluded from this GRC.

30.2.1.2. Discussion

First, it is clear pursuant to D.16-06-054 that costs relating to the Aliso Canyon leak be excluded from the revenue requirement request in this GRC and both Applicants and CFC do not dispute this fact. The issue then is whether the

³⁶⁵ Exhibit 387 at 1.

Aliso Canyon leak which was discovered in October 2015 caused Sempra's EMF for Excess Property insurance to increase from 1.0 to 1.25 in 2016 and whether this increase in EMF affects the TY2019 forecast.

Applicants contend that the insurance premium is affected by a variety of factors that the insurer, Oil Insurance Limited (OIL), considers. In addition to the EMF, such as business sector assets, deductible levels, insurance program structure, and overall OIL membership losses.³⁶⁶ Applicants add that many of factors are dependent on OIL membership performance as well as company performance.

Based on Applicants' testimony, we find that Applicants do not contest that the EMF and the company's performance have an effect on the premium charged except that many other factors also contribute to the determination of the premium. We agree that many factors, such as those mentioned by Applicants, affect the determination of the premium. However, we find that the nature of the EMF is that it adjusts the calculated premium based on the modifier applied. In other words, while the factors that Applicants mentioned affect the determination of premium to be assessed, the company's EMF score is then used to modify or adjust this determined premium to arrive at the actual premium that will be charged.

We agree with CFC that EMF is based on losses and find that actual or possible insurance claims relating to the Aliso Canyon incident and the assessment of Applicants' future risk negatively impacted Applicants' EMF

³⁶⁶ Exhibit 240 at NKC-14.

modifier. Thus, we agree with CFC that the Aliso Canyon incident is a primary factor for Applicants' higher EMF beginning in 2016.

Applicants argue that the OIL premium for 2016 actually decreased compared to 2015 despite the higher EMF and gross assets and increased in 2017 despite the same EMF. However, as explained above, we find that EMF only adjusts the calculation of the premium that was determined based on different factors. Thus, we find that the OIL premium in 2016 would have been even lower compared to 2015 had Applicants' EMF remained at 1.0 and that the premium in 2017 increased, as compared to 2016, because of factors other than EMF.

The increase of Applicants' EMF from 1.0 to 1.25 in 2016 means that the OIL premium was around 20 percent higher because of the higher EMF. Thus, CFC recommends reducing Applicants' forecast by 20 percent. For 2019, we assume that the EMF will remain at 1.25 since Applicants did not present a different figure. However, we are cognizant of the fact that the Aliso Canyon incident may have a reduced impact in 2019 compared to 2016 and that other factors may affect the 2019 EMF. Because the exact impact of the Aliso Canyon incident in the 2019 EMF cannot be specifically determined absent other evidence, we reduce the impact attributable to the Aliso Canyon incident to one-half. Therefore, we find that the requested amount for Excess Property insurance should be reduced by 10 percent which makes the authorized amount \$8.017 million.

Regarding the forecasts for Primary Property and Other Property insurance, we find that Applicants presented sufficient evidence to justify the requested amounts. We find these types of insurances to be necessary and many are types that are generally obtained for businesses. We also agree with the

forecast methodology employed which utilizes the expertise of Applicants' insurance providers. We likewise agree with the allocation methods used. No party provided any objections to both the forecast methods and allocation methods that were used. Thus, we find that the requested amounts should be authorized without any modifications. This makes the total amount authorized under Property insurance \$15.185 million.

Liability Insurance

Liability insurance provides coverage for legal liability resulting from third-party claims. Costs are divided into six categories and the table below shows the TY2019 forecast for the Corporate Center and the allocated amounts for Applicants for each of the six cost categories listed below. A forecast was developed for each individual type of insurance policy. The forecasts are primarily based on forecasts provided by Sempra's primary insurance broker.

Liability Insurance	Corporate Center TY2019 Forecast	Utility Allocation
General Excess	\$69,224,000	\$52,783,000
Wildfire	\$89,226,000	\$89,190,000
Director & Officers	\$1,547,000	\$774,000
Fiduciary	\$713,000	\$544,000
Workers Comp	\$4,226,000	\$3,887,000
Other Liability	\$1,988,000	\$1,385,000
Total	\$166,965,000	\$148,562,000

General Excess

Provides coverage for third-party property damage, bodily and personal injury. Coverage also includes operational pollution liability, auto liability, and employer liability. Costs are allocated using the multi-factor basic methodology.

Wildfire liability

Provides coverage for third-party liability for bodily injury, property damage, or personal injury arising from wildfires. 99.5 percent of costs are

allocated to SDG&E using the miles of overhead electrical line as the factor in the causal/beneficial methodology. This subsection also includes forecast costs for wildfire property damage reinsurance which provides coverage for third-party legal liability for property damage arising from wildfires. Similarly, 99.5 percent of costs are allocated to SDG&E.

Directors & Officers

Provides coverage for corporate directors and officers against claims for financial loss arising from mismanagement. Coverage does not include fraudulent and criminal acts. Costs are allocated using the multi-factor split with 50 percent being allocated to Applicants.

Fiduciary

Coverage from liability from wrongful acts committed by employee benefit program fiduciaries. Costs are allocated using the multi-factor basic methodology.

Workers Compensation

Provides coverage for employee job-related injuries or disease. Benefits and amounts to be paid to employees are set and required by the state based upon the type and extent of the injury. Sempra also procures excess workers' compensation insurance that provides coverage for large claims. Costs are allocated based on payroll of business units covered.

Other Liability

Includes: (a) cyber insurance for loss of information relating to employees and customers due to a cyber incident which is allocated using the multi-factor basic methodology; (b) auto liability insurance for all automobiles not owned by SDG&E and SoCalGas which is allocated based on the number of vehicles owned by a business unit; (c) insurance for the APS Yuma Transmission System which is

100 percent allocated to SDG&E; and (d) railroad protective insurance that provides coverage within a railway's right of ways which is directly allocated to the applicable business unit. Broker service fees are included in this subgroup and represents fees paid to brokers for their services. Costs for broker fees are allocated using the multi-factor basic method.

30.2.1.3. Positions of Intervenors

TURN states that the amount allocated to utilities for Directors and Officers (D&O) should be reduced by 50 percent following Commission's position in D.13-05-010 that shareholders bear 50 percent of the costs. TURN also recommends adjustments to the multi-factor basic allocation factors resulting in a \$1.56 million reduction for SoCalGas and a \$1.16 reduction for SDG&E.

UCAN proposes a five-year average of SDG&E's 2012 to 2016 wildfire costs as a starting point.

FEA recommends using 2017 actual costs for all categories except for Other Liability. FEA explains that 2017 costs represent the most recent known and measurable amount in the record. Reductions are recommended for SDG&E for the first five liability insurance categories in the amounts of \$5.393 million, \$7.765 million, \$24,000, \$26,000, and \$242,000 respectively.

30.2.1.4. Discussion

In D.13-05-010, the Commission found that D&O insurance protects Sempra's Board members and officers from catastrophic losses which is a benefit that accrues to shareholders rather than ratepayers and went on to state that 50 percent of costs should be borne by shareholders.³⁶⁷ We see no reason to

³⁶⁷ D.13-05-010 at 851.

deviate from this approach for the same reasons stated therein. Applicants claim that 50 percent of D&O costs are already allocated to them but following what is stated in D.13-05-010 is that 50 percent of the allocated costs to SDG&E and SoCalGas should be borne by shareholders and not 50 percent of the total costs to the Corporate Center. Therefore, we find that D&O costs should be reduced by 50 percent and that \$387,000 should be authorized. As for TURN's recommended adjustment to the multi-factor basic calculation, we agree with Applicants that there is not enough basis for TURN's recommendation and that the adjustment seems to result from the inclusion of Oncor into the calculation and as pointed out by Applicants' testimony, Oncor is excluded from coverage in Sempra's liability insurance program.³⁶⁸

With respect to UCAN's proposal concerning the forecast of SDG&E's wildfire insurance costs, we find that historical averages would not be reflective of anticipated insurance premium costs in TY2019 for wildfire insurance in light of the recent wildfires in 2017 and 2018. Specifically, the 2018 wildfires occurred after SDG&E had already prepared its forecast and so these recent events were not taken into consideration in their entirety. Although wildfire risk has become an annual concern, it is still very difficult to predict the intensity and damage that will be caused by wildfires and how known and unknown events will impact costs. As insurance premiums continue to rise to unprecedented levels, we agree with UCAN's recommendation that Applicants should explore alternative options to conventional insurance and should include these in testimony during their next GRCs.

³⁶⁸ Exhibit 240 at NKC-13.

As for FEA's recommendation to use 2017 actual expenses for the TY2019 forecast, we find that Applicants presented sufficient explanation through testimony as to why 2017 actual expenses and also other historical costs will not be reflective of projected 2019 costs for the various categories of liability insurance. Applicants cite year to year fluctuations influenced by factors some of which are outside their control. And most especially, anticipated costs for wildfire insurance are expected to exceed historical levels in light of the recent California wildfires in 2017 and 2018.

In sum, and based on the above discussion, we find that the amounts requested for the six categories under Liability Insurance are reasonable and should be approved except for D&O which should be reduced by \$387,000. This makes the total amount for Liability Insurance that should be authorized \$148.175 million.

30.2.1.5. Liability Insurance Premium Balancing Account

Applicants request authority to establish the Liability Insurance Premium Balancing Account (LIPBA), a two-way balancing account for liability insurance premiums. Applicants cite to the uncertainty regarding the possible need for and cost of additional insurance because of market fluctuations in the cost of liability insurance.

ORA and UCAN do not oppose the LIPBA but each recommend revisions to what Applicants propose. ORA proposes that the LIPBA should only be applicable to the level of insurance coverage requested in the GRC and that purchases of additional coverage require the filing of an application. UCAN recommends that the LIPBA be restructured to provide greater Commission review and that SDG&E be required to present alternatives that were considered

in any future reasonableness review. UCAN also proposes that the LIPBA only apply to SDG&E.

FEA opposes the establishment of the LIPBA and states that liability insurance costs are normal costs of doing business and are not beyond the utilities' control.

We reviewed the arguments raised by Applicants, ORA, UCAN, and FEA as well as the testimony submitted by the parties in support of their positions. Based on our review, we find that Applicants raised various concerns that support the creation of the LIPBA. Market fluctuations and the recent wildfires in California make insurance costs difficult to predict. There are also many factors that affect insurance premiums and certain factors are outside of Applicants' control or are difficult to foresee. This in turn makes it difficult to provide an accurate forecast. The LIPBA allows Applicants to address these uncertainties in a timely manner and at the same time ensure that there is adequate insurance coverage for known risks.

We agree with FEA that most businesses include some type of liability insurance such as workers compensation and auto insurance. However, we find that in the case of Applicants, some of the risks that require adequate insurance coverage are atypical to other businesses and these include risks that can lead to severe damage and risks that are hard to predict. As stated in Applicants' testimony, costs for certain risks may be affected by events or losses worldwide and we agree that there are certain elements that affect insurance costs for certain types of liability insurance that are outside Applicants' control. Therefore, we find that authority to establish the LIPBA should be granted in this decision. The LIPBA also addresses some of FEA's concerns about using the most recent costs.

This is because forecast costs will be adjusted with more recent data through the balancing account mechanism being proposed in the LIPBA.

With respect to the modifications proposed by ORA and UCAN, we agree with ORA that there should be some mechanism within which to review additional insurance expenditure that was not requested in these GRCs. The Commission only reviewed and considered the types of insurance and level of coverage that were presented in the GRC and it cannot ascertain the reasonableness of additional and other types of insurance that may be purchased and recorded in the LIPBA. However, we also recognize Applicants' concern about being exposed to increased risk for a significant period while waiting for approval of an application in cases where it finds a need to purchase other and additional liability insurance coverage. Thus, we find that Applicants should be required to file a Tier 2 advice letter when they seek recovery of costs for additional liability insurance coverage that were not requested in these GRCs. This approach balances the concerns raised by ORA and UCAN about greater Commission review and Applicants' concern about exposure to additional risk for a significant period.

As for the other concerns raised by UCAN, we find that a showing of alternatives in any future reasonableness review of the LIPBA should be included. Recovery of any additional coverage not contemplated in this application will also be reviewed through the advice letter process that is being required for such instances. We also disagree that the LIPBA should only be applicable to SDG&E as SoCalGas is also exposed to liability insurance fluctuations for different risks.

To summarize, Applicants' request for authority to establish the LIPBA as a two-way balancing account should be granted with a modification that a Tier 2

advice letter should be filed for recovery of costs of additional liability insurance coverage that were not requested in these GRC applications.

30.2.2. Surety Bonds

Surety bonds guarantee the contractual performance of Sempra's obligations to other parties. These bonds are usually required by city, state, and federal government agencies. Bond premiums are paid either as a one-time payment for the life of the bond or as an annual premium. Costs are directly assigned to the business unit requiring the bond. The forecast for surety bonds for TY2019 is \$319,000 for the Corporate Center with \$192,000 to be allocated to applicants.

Parties do not oppose the forecast for Surety Bonds and we find the request to be reasonable and supported by the evidence upon review of the request. Therefore, we find that the requested amount of \$192,000 for Surety Bonds should be approved.

31. Compensation and Benefits

This section addresses the TY2019 forecast for Compensation and Benefits for both SDG&E and SoCalGas. Both utilities have the same Compensation and Benefits programs which are made up of the following components: base pay, variable pay, long-term incentives, special recognition awards, health benefits, welfare benefits, retirement benefits, and other benefits. Because the Compensation and Benefits programs for both utilities are the same, we combine our discussion of the program components and then apply the discussion to each utility's TY2019 forecast. Certain benefits such as long-term disability, pension, and post-retirement benefits other than pension are not included in this section and will instead be addressed in the following section that discusses Pension and Post-Retirement Benefits other than Pension.

As stated in section 4.2 of the decision, Public Utility Code section 706 has been amended such that beginning January 1, 2019, Applicants are no longer able to recover from ratepayers the annual salaries, bonuses, benefits, or other consideration paid to officers and these must instead be funded by shareholders. However, because of timing considerations relating to the late stage of the proceedings at the time the statutory change became effective, the decision disallows cost centers that are composed entirely of officer salaries, bonuses, and benefits and directs Applicants to track officer salaries, bonuses, and benefits in cost centers that are embedded with other costs in their respective OCMA's. The OCMA balances shall be trued-up in Applicants' respective year-end adjustment filings for 2019 and the amounts refunded to ratepayers. Officer salaries, bonuses, and benefits are to be excluded from the revenue requirements for PTYs 2020 and 2021.

A total compensation study was conducted as part of Applicants' TY2019 GRCs in compliance with Commission decisions.³⁶⁹ The study was conducted to evaluate Applicants' total compensation relative to the external labor market.³⁷⁰ After making offers to three vendors, Applicants selected Willis Towers Watson (WTW), a global advisory, broking and solutions company, to conduct the study. According to Applicants, ORA was requested to participate in the study but declined. ORA participated in Applicants' prior compensation studies. The result of the total compensation study conducted by WTW is attached as Appendix A to Exhibit 208. In sum, the study concludes that both SDG&E's and

³⁶⁹ D.87-12-066, D.89-12-057, and D.96-01-011.

³⁷⁰ Exhibit 208 at DSR-6.

SoCalGas' total compensation levels fall within the competitive range of plus or minus 10 percent of the average mean of the competitive market. According to the study, SDG&E's total compensation is at plus 0.4 percent while SoCalGas' is at -0.7 percent.

31.1. Compensation

The Compensation package for SDG&E and SoCalGas consists of basepay, short-term incentive compensation or variable pay for non-executives and executives, long-term compensation, and special recognition awards. The table below shows the TY2019 forecasts for the different Compensation components, other than base pay, for SoCalGas and SDG&E, as well as the difference from 2016 recorded costs. These components are discussed below including base pay which shall be discussed first.

Compensation	SoCalGas		SDG&E	
	TY2019	Difference from 2016	TY2019	Difference from 2016
Non-Executive Incentive Compensation	\$75,680,000	\$12,042,000	\$64,523,000 ³⁷¹	\$4,230,000
Executive Incentive Compensation	\$3,410,000	\$361,000	\$4,020,000	-\$108,000
Long-Term Incentive Plan	\$10,029,000	\$2,442,000	\$8,570,000	-\$173,000
Spot Cash Program	\$978,000	\$547,000	\$970,000	\$558,000
Employee Recognition Program	\$646,000	\$547,000	\$339,000	\$253,000
Subtotal	\$90,743,000		\$80,617,000	

31.1.1. Base Pay

SoCalGas and SDG&E participate in several survey databases sponsored by major human resources consulting firms in order to ensure that pay structures

³⁷¹ Revised from \$66.718 million to \$64.523 million in the Update Testimony (Exhibit 514) at Attachment I. The total amounts do not include this revision.

and ranges are competitive and reflect the market rate in which Applicants compete for labor. Base pay and pay grades for represented jobs are subject to collective bargaining agreements while non-represented jobs allow for individual differentiation based on performance, skills, and experience. Base pay for individual employees are included in the labor component of the various cost centers where the FTEs appear in and are incorporated in the forecasts for those cost centers. As such, review of such costs is conducted as part of the review of the sections that they appear in and not in this section of the decision.

31.1.2. Incentive Compensation Plan

According to Applicants, Incentive Compensation Plan (ICP) has been a longstanding part of their total compensation strategy. Costs were forecast using a five-year historical average.

31.1.2.1. Non-Executive ICP

All non-represented employees are eligible to participate in the ICP. Awards are based on performance metrics which include individual performance, safety and reliability, customer satisfaction and financial health. Since 2017, Applicants state that they have placed a higher emphasis on the safety component. The list below shows the major performance metrics and their corresponding percentage from total ICP:

Individual Performance: 50%

Safety and Public Safety Related Operational Measures: 35%

Customer Service: 5%

Financial Health: 10%

Table DSR-7 of Exhibit 208 provides a more detailed breakdown of the above major components of the ICP.³⁷²

31.1.2.2. Executive ICP

Executive ICP are awarded to SoCalGas and SDG&E executives and are no longer recoverable from ratepayers pursuant to Pub. Util. Code § 706. Amounts corresponding to Executive ICP of \$3.410 million for SoCalGas and \$4.020 million for SDG&E are therefore excluded.

31.1.3. Long-Term Incentive Plan

Long-Term Incentive Plan (LTIP) awards are restricted stock awards granted to qualifying executives. The awards are performance-based and service-based. Pursuant to Pub. Util. Code § 706, these amounts are no longer recoverable from ratepayers and the requested amounts of \$10.029 million for SoCalGas and \$8.570 million for SDG&E are therefore excluded from the adopted forecast.

31.1.4. Special Recognition Awards

Special recognition awards are awarded to employees and teams for outstanding achievements and exceptional customer service, process improvements, and innovation.

Spot Cash Program

Cash awards that range from \$250 to \$10,000. Costs were forecast using a five-year average.

Employee Recognition Program

³⁷² Exhibit 208 Table DSR-7 at DSR-13.

Nominal non-cash awards valued at \$100 or less. Typical awards take the form of gift cards, event tickets, etc. Costs were forecast at \$75 per employee.

31.1.5. Positions of Intervenor

ORA, TURN and NDC provided comments to this section. Because costs for Executive ICP and LTIP are excluded from the adopted revenue requirement, intervenor positions regarding these need not be discussed.

ORA recommends allowing 42.5 percent of Non-Executive ICP costs based on allowing only 50 percent of costs for individual performance and safety and operations and disallowing ICP costs for financial health and customer service. ORA also recommends using 2016 costs for the Spot Cash and Employee Recognition Programs because Applicants were able to maintain service levels and retain employees despite the lower than average spending for these categories.

TURN recommends \$51.8 million for SoCalGas' Non-Executive ICP costs and \$48.0 million for SDG&E based on reductions in funding percentages for several ICP metrics including zero percent funding for financial metrics. TURN also recommends using a three-year average for the Employee Recognition Program because recorded costs are significantly lower than the amounts being requested.

NDC identified a headcount adjustment for 2013 which changes the five-year average of the Non-Executive ICP for SDG&E to \$64.523 million or \$2.195 million lower than SDG&E's requested amount. SDG&E agrees with the adjustment and reduced its forecast in the Update Testimony (Exhibit 514) at I-2. NDC also argues that the average per headcount ICP cost should be applied to union employees whereas SDG&E used the average annual ICP cost.

31.1.6. Discussion

As stated above, base pay is incorporated in labor costs for the cost centers that they appear in and are addressed in those sections of the decision. Executive ICP and LTIP costs are excluded pursuant to the revision to Public Utilities Code section 706 which became effective on January 1, 2019 disallowing ratepayer recovery of officer salaries, bonuses, benefits, and other consideration. We also discussed in Section 4.2 of the decision that we will disallow funding requests for cost centers that are entirely made up of officer salaries, bonuses, benefits, and other consideration such as the Executive ICP and LTIP.

With respect to the ICP, Applicants argue that this is part of their total compensation package which, according to the study conducted by WTW, is around market level. However, this alone does not mean that we should no longer examine the components or mechanics of the ICP especially because Applicants are regulated entities whose expenses are in large part funded by ratepayers. With regards to the various performance metrics for the ICP, we agree with Applicants that we should not micromanage Applicants to the extent of dictating what the performance metrics should be. However, we find that we can deny or reduce funding for certain metrics that are not reasonable or do not provide tangible benefits to ratepayers since ratepayers are the ones funding these costs.

We reviewed the various performance metrics for the ICP and find that most of the performance metrics provide tangible benefits to ratepayers in that they encourage and promote either safety, operational efficiency, reduced costs, improved service, or a policy that the Commission. While some metrics also align with shareholder goals, we find that these are not necessarily inconsistent with ratepayer benefits.

However, with respect to the financial metrics, we find that these primarily benefit the utilities and its shareholders. Applicants argue that the financial metrics provide benefits to ratepayers in the form of lower interest rates but we find that this is not substantiated or quantified by the evidence presented. We also find any benefit resulting from achieving Applicants' financial goals to be incidental and secondary to what we consider as the primary goal of the financial metrics which is to reach a certain level of income or earnings. After all, achieving a target interest level for borrowing is not one of the metrics that triggers the award. Therefore, we find that 10 percent of the ICP, or the amount representing the financial metrics, should be disallowed.

With respect to the issue raised by NDC, we find that SDG&E multiplied the assumed headcount by the average ICP costs per person for non-executive employees while only applying the average ICP costs for union employees without considering the assumed headcount. For consistency and increased accuracy, we find it reasonable to apply the same method of using headcounts to derive the ICP costs for both sets of employees. In addition, we agree with NDC that SDG&E used an increasing headcount each year for 2017 to 2019 even if the headcounts for each group of employees do not show an increase from 2012 to 2016.³⁷³ We also agree with NDC that applying a constant 2016 headcount for non-executive and union ICP costs is reasonable. Adding the above 10 percent reduction for financial metrics results in an amount of \$52.505 million for SDG&E that should be authorized.

³⁷³ NDC Opening Brief at 22 to 24 and Exhibit 212 at 19 to 20.

The above adjustments result in \$68.112 million for SoCalGas and \$52.505 million for SDG&E³⁷⁴ for Non-Executive ICP that should be authorized. TURN also objected to the ICP amounts allocated from the Sempra Corporate Center but did not elaborate what components or what percentage thereof of the Corporate Center ICP are to be excluded. OSA also objected to some of the safety-related metrics but as mentioned above, we leave the determination of what performance metrics to include to Applicants and instead determine whether these are reasonable and whether the costs thereof are recoverable from ratepayers.

With regards to Spot Cash, we find the use of a five-year average to develop the TY2019 forecast is appropriate because it better reflects high and low values during the past five years. In contrast, the 2016 values that ORA recommends represents the lowest values during the last five years. In addition, the 2016 levels will have been impacted by employees that were temporarily reassigned to perform work related to the Aliso Canyon gas leak incident. These employees will be returning to perform their regular duties.

For the Employee Recognition Program, we find TURN's proposal to utilize a three-year average from 2015 to 2017 to be more reflective of projected costs. SDG&E and SoCalGas used a zero-based method and forecast costs at \$75 per employee. However, we find that a historical average better reflects project costs for the test year as the Employee Recognition Program is meant to reward individual employees for outstanding achievements and is not meant to be

³⁷⁴ This amount applies the headcount adjustment identified by NDC which reduced the total amount requested to \$64.5 million and the headcount adjustment for calculating the ICP costs for union employees.

awarded to every single employee. Also, as argued by TURN, costs during 2015 to 2017 were much lower for both SDG&E and SoCalGas. Exhibit 498 shows the cost per employee from 2015 to 2017³⁷⁵ and the average for SDG&E was around \$28 per employee and for SoCalGas around \$11 per employee. SDG&E and SoCalGas provided no explanation for why costs are expected to be \$75 per employee. Based on the above, it is reasonable to adopt TURN's recommendation which results in \$92,000 for SoCalGas and \$119,000 for SDG&E. With respect to ORA's recommendation of using 2016 costs, we find that a three-year average better reflects projected costs for TY2019 rather than costs from a single year.

In sum, Non-Executive ICP is reduced to \$68.112 million for SoCalGas and \$52.505 million for SDG&E, Executive ICP and LTIP are denied, the Spot Cash requests are adopted, and the Employee Recognition Program costs are reduced to \$92,000 for SoCalGas and \$119,000 for SDG&E.

31.2. Benefits

The Benefits included in this section of the decision are health benefits, welfare benefits, retirement benefits, and other benefit programs. As discussed at the beginning of this section, certain benefits are discussed such as long-term disability, pension, and post-retirement benefits other than pension are addressed in another section.

31.2.1. Health Benefits

Health Benefits include medical, dental, vision, wellness, employee assistance plan (EAP), and mental health. The forecast for TY2019 is

³⁷⁵ Exhibit 498 at 79.

\$105.050 million³⁷⁶ for SoCalGas and \$63.861 million³⁷⁷ for SDG&E. The table below shows the breakdown of costs for each health benefit category as well as the difference from 2016 recorded costs.

Health Benefits	SoCalGas		SDG&E	
	TY2019	Difference from 2016	TY2019	Difference from 2016
Medical	\$96,023,000 ³⁷⁸	\$15,398,000	\$56,204,000 ³⁷⁹	\$11,863,000
Dental	\$5,052,000	\$2,465,000	\$3,993,000	\$1,552,000
Vision	\$629,000	\$54,000	\$353,000	\$35,000
Wellness	\$707,000	\$281,000	\$1,117,000	\$326,000
EAP	\$788,000	\$60,000	\$291,000	\$13,000
Mental Health	\$1,851,000	\$462,000	\$1,903,000	\$499,000
Subtotal	\$103,347,000		\$63,453,000	

Medical

Increased costs are based on forecasted medical rate escalation as well as anticipated changes in the number of employees. The medical trend forecast was prepared specifically for SoCalGas and SDG&E by WTW taking into account workforce demographics, historical utilization data, and medical plan design.³⁸⁰ Projected rate increases are 8.0 percent for 2018 and 7.0 percent for 2019.

Dental

³⁷⁶ Revised from \$105.050 million to \$103.347 million in the Update Testimony (Exhibit 514) at Attachment H.

³⁷⁷ Revised from \$63.861 million to \$63.453 million in the Update Testimony (Exhibit 514) at Attachment I.

³⁷⁸ Revised from \$96.023 million to \$94.320 million in the Update Testimony (Exhibit 514) at 8.

³⁷⁹ Revised from \$56.204 million to \$55.796 million in the Update Testimony (Exhibit 514) at 8.

³⁸⁰ Exhibit 208 at DSR-30.

TY2019 costs are based on 2017 rates adjusted for projected inflation and changes in the number of employees.

Vision

TY2019 costs are also based on 2017 rates adjusted for projected inflation and changes in the number of employees.

Wellness Programs

Aims to improve employee health and productivity by promoting a healthy lifestyle and illness prevention.

EAP

Provides employees and eligible dependents with counseling and treatment services for various personal problems that may have a negative impact on job performance.

Mental Health

Covers treatment for more serious mental health conditions including substance abuse.

31.2.2. Welfare Benefits

Welfare benefits provide financial resources when injury, disability, or death occurs. Business Travel Insurance and Life Insurance also form part of Welfare Benefits.

Welfare Benefits	SoCalGas		SDG&E	
	TY2019	Difference from 2016	TY2019	Difference from 2016
Accidental Death and Dismemberment	\$73,000	\$14,000	\$96,000	\$22,000
Business Travel Insurance	\$51,000	\$3,000	\$27,000	\$2,000
Life Insurance	\$1,798,000	\$180,000	\$710,000	\$108,000
Subtotal	\$1,922,000		\$833,000	

Accidental Death and Dismemberment (AD&D)

Premiums are expected to remain relatively flat at around \$0.156 per \$1,000 of coverage and increased costs reflect projected increases in the number of employees.

Business Travel Insurance

Additional life insurance coverage while traveling for business purposes. Projected increases are for premium inflation and projected increase in the number of employees.

Life Insurance

Basic life insurance equivalent to annual pay. Projected increases are for increased salaries and projected increase in the number of employees.

31.2.3. Retirement Benefits

Retirement Benefits are provided to all employees and include a defined benefit pension plan, a defined contribution (401k) retirement savings plan, and postretirement health and welfare benefits.

Retirement Benefits	SoCalGas		SDG&E	
	TY2019	Difference from 2016	TY2019	Difference from 2016
Retirement Savings Plan	\$25,409,000	\$4,058,000	\$17,369,000	\$2,891,000
Nonqualified Savings Plan	\$300,000	\$25,000	\$245,000	\$20,000
Supplemental Pension	\$1,920,000	-\$367,000	\$2,370,000	-\$819,000
Subtotal	\$27,629,000		\$19,984,000	

Retirement Savings Plan (RSP)

Provides employees with a means for saving for retirement. Applicants encourage participation by providing a matching contribution. Projected costs for matching contribution are based on 2016 actual costs.

Nonqualified Savings Plan

Nonqualified Savings Plan or deferred compensation plan allows pre-tax contributions³⁸¹ for employees with matching contributions from Applicants.

Projected costs are based on 2016 costs.

Supplemental Pension

Cost forecasts represent the projected benefit payments including payments to current retirees.

31.2.4. Other Benefit Programs

These benefits provide opportunities to enhance financial and technical knowledge through external education programs. Certain recognition programs are included to promote a work environment that recognizes Applicants' employees.

Other Benefit Programs	SoCalGas		SDG&E	
	TY2019	Difference from 2016	TY2019	Difference from 2016
Benefits Administration Fees	\$1,107,000	-\$8,000	\$667,000	-\$2,000
Educational Assistance	\$1,087,000	\$129,000	\$508,000	\$67,000
Emergency Childcare	\$217,000	\$29,000	\$159,000	\$27,000
Mass Transit Incentive	\$1,098,000	\$112,000	\$86,000	\$15,000
Retirement Activities	\$180,000	-\$59,000	\$67,000	-\$142,000
Service Recognition	\$254,000	\$0	\$108,000	-\$18,000
Special Events	\$532,000	\$61,000	\$0	\$0
Subtotal	\$4,475,000		\$1,595,000	

Benefits Administration Fees

Include fees for legally required audits, administrative fees, record-keeper fees, actuarial, and other professional service fees.

³⁸¹ The Nonqualified Savings Plan allows contributions in excess of the limits provided in the RSP.

Educational Assistance

Provides reimbursement of tuition for degree or certificate programs that maintain or enhance skills necessary to perform current and prospective jobs within the company.

Emergency Childcare

Provides emergency childcare services when an employee's primary childcare resource is unavailable.

Mass Transit Incentive

Transit subsidies for public transportation and carpools.

Retirement Activities

Gifts and a retirement breakfast to recognize a retiring employee's past service

Service Recognition

Awards given to employees on their fifth anniversary and every five years thereafter.

Special Events

Once a year events where all employees gather in one place.

31.2.5. Positions of Intervenors

ORA's recommendations are as follows:

Health Benefits: medical escalation rate of 4.25 percent and zero for Wellness.

Welfare: no objections to Applicants' forecasts.

Retirement Benefits: zero for Nonqualified Savings Plan and Supplemental Pension.

Other Benefit Programs: 50 percent for Service Recognition and zero for Emergency Childcare, Retirement Activities, and Special Events.

TURN's recommendations are as follows:

Health Benefits: medical escalation of 6 percent

Welfare:- no objections to Applicants' forecasts.

Retirement Benefits: 50 percent for Nonqualified Savings Plan and Supplemental Pension.

Other Benefit Programs: five-year average for Benefits Administration Fees and zero for Retirement Activities and Special Events.

31.2.6. Discussion

31.2.6.1. Health Benefits

Regarding the medical premium escalation rate to be applied, we reviewed Applicants' proposal as well as the alternative recommendations by ORA and TURN. TURN's recommendation is based on Applicants' actual average medical premium increase of 5.64 percent. TURN adds that Applicants' actual medical premium rate increases have consistently been lower than previous forecasts. For its part, ORA used the average between the Kaiser Family Foundation Health Benefits Survey of average family premium increase for employers of 3.0 percent and the projection by the Price Waterhouse Cooper Health Research Institute of 5.5 percent.

However, we find that the medical trend forecast prepared by Willis Towers Watson is more reasonable to apply because the forecast was prepared specifically for SoCalGas and SDG&E taking into account workforce demographics, location, and medical plan design which we find to be more reflective of Applicants' medical premium costs. The forecast is based on the local health care market of Southern California as opposed to national trends and considers the slightly older workforce of SoCalGas and SDG&E as well as larger family sizes which means greater coverage for dependents. Therefore, we find that Applicants' proposed medical premium escalation rates of 8.0 percent for 2018 and 7.0 percent for 2019 are more appropriate and should be authorized.

ORA objects to the funding for Wellness because it finds the services duplicative of what is available under medical plans. Based on our review

however, we find that many of the services provided differ in that the Wellness services focus more on promoting a healthy lifestyle and early detection and prevention of illnesses rather than treatment. The programs include fitness programs, weight and stress management, smoking cessation, and other programs. While some services are also available under the medical plans provided such as getting influenza vaccinations, providing the services onsite encourages greater participation which leads greater prevention of illnesses from occurring. Other programs such as the safety stand down events are also linked with safety programs. Based on the above, we find the funding request for the Wellness reasonable and should be approved.

We find the Dental, Vision, EAP and Mental Health programs to be standard benefits provided to employees by many companies and we find the forecast costs to be reasonable and should be approved. The forecast for Mental Health is impacted by the medical escalation rate which was discussed above.

To summarize, we find that Applicants' forecasts for Health Benefits including a medical escalation rate of 8.0 percent for 2018 and 7.0 percent for 2019 should be approved.

31.2.6.2. Welfare Benefits

We reviewed the forecasts under Welfare and find these to be reasonable. We find these benefits to be standard benefits that many companies provide to their employees. Costs were based on inflation and factors directly affecting the programs such as number of employees and increase in salaries to calculate life insurance benefits. Parties did not object to the funding requests for Welfare benefits. Thus, we find that Applicants' requested amounts should be approved.

31.2.6.3. Retirement Benefits

We find that the RSP is another standard benefit or equivalent thereof that companies normally provide to its employees. This is also an important benefit with respect to hiring and retaining employees and we find it reasonable to authorize funding for this request. Parties do not object to the necessity of the RSP and the Applicants' TY2019 forecasts.

With respect to both the Nonqualified Savings Plan and Supplemental Pension, we find that these plans are generally applicable only to executives and other high-income employees. Thus, we find that these plans benefit both shareholders and ratepayers and so it is reasonable for both to share costs equally. This is consistent with past GRC decisions where the Commission deemed that 50 percent shareholder funding of costs is appropriate and reasonable.³⁸² We note that a large part of the funding for these costs pertain to officer benefits that should be recorded in Applicants' respective OCMA's and later on refunded to ratepayers as discussed in Section 4.2 of this decision concerning cost centers that contain both officer and employee salaries, bonuses, and benefit costs.

To summarize, Applicants' TY2019 forecasts for the RSP and 50 percent of the forecasts for both the Nonqualified Savings Plan and Supplemental Pension, are authorized.

³⁸² D.13-05-010 (SDG&E and SoCalGas TY2012 GRC), D.15-11-021 (SCE TY2015 GRC), and D.14-08-032 (PG&E TY2014 GRC).

31.2.6.4. Other Benefit Programs

We agree with the forecast methodologies that Applicants utilized because they are based on specific cost drivers for each benefit. The forecast methodologies are explained for each benefit in Exhibit 211.³⁸³

Parties do not object to the Benefits Administration Fees, Educational Assistance, and Mass Transit benefits and we also have no objections to these and find the forecast amounts to be reasonable. We also have no objection to the funding request for Service Recognition and find that this benefit is a common benefit provided by companies to recognize employees for their length of service and loyalty to the job that they perform.

With regards to Retirement Activities and Special Events, we agree with ORA and TURN that funding for these benefits should be denied because they have little connection to and provide no tangible benefits to ratepayers based on the evidence presented. We also find that these benefits do not improve performance as they are granted to all employees and have little to no impact in hiring new employees and retaining existing employees.

With regards to Emergency Childcare, Applicants cite good reasons for authorizing the proposed costs such as in emergency situations or in non-emergency situations on occasion of school closings, business travel, or return from maternity. In addition, the program is of limited application when an employee's primary childcare resource is unavailable. We find that the program benefits ratepayers because it reduces employee absences and helps ensure that tasks are timely and adequately performed. Based on the above, we

³⁸³ Exhibit 211 at DSR-37.

find it reasonable to allow the proposed costs for Emergency Childcare in this instance.

To summarize, we find that the funding requests for Benefits Administration Fees, Educational Assistance, Mass Transit Incentive, Service Recognition, and Emergency Childcare should be authorized and the funding requests for Retirement Activities and Special Events should be denied.

32. Pensions and Post-Retirement Benefits Other than Pension

This section addresses the TY2019 forecasts of SDG&E and SoCalGas for Pension and Post-retirement Benefits Other than Pension (PBOP). The programs for both utilities are generally the same and so we combine the discussion for both utilities.

As stated in Section 4.2 of the decision, Pub. Util. Code § 706 has been amended and from January 1, 2019, Applicants are no longer able to recover from ratepayers the annual salaries, bonuses, benefits, or other consideration paid to officers and these must instead be funded by shareholders. But because of timing considerations relating to the late stage of the proceedings at the time the statutory change became effective, the decision directs Applicants to track officer pension and PBOP costs in their respective OCMA's. The OCMA balances shall later on be trued-up in Applicants' respective year-end adjustment filings for 2019 and the amounts shall be refunded to ratepayers. Officer pension and PBOP costs are to be excluded from the revenue requirements for PTYs 2020 and 2021.

32.1. Pension

The TY2019 forecast for pension costs is \$202.830 million for SoCalGas and \$63.970 million for SDG&E. This represents increases of \$132.480 million for

SoCalGas and \$63.970 million for SDG&E from 2016 recorded expenses. SDG&E had zero pension costs for 2016 based on the minimum required contributions.

SDG&E and SoCalGas offer pension benefits to all employees. SoCalGas provides pension benefits to approximately 8,200 active employees and 5,600 retirees, survivors, and terminated participants entitled to future benefits while SDG&E provides pension benefits to approximately 4,000 active employees and 2,700 retirees, survivors, and terminated participants entitled to future benefits. Employees are fully vested in their pension benefits after five years of service.

SoCalGas provides a traditional benefit plan which provides a retirement benefit based on final average earnings and years of service for union employees hired prior to January 1, 2012. Since then, all union employees became subject to the Cash Balance Plan. Non-union employees are subject to the Cash Balance Plan. The Cash Balance Plan provides retirement credits equal to 7.5 percent of eligible earnings and interest on their account balances up to the date of distribution.³⁸⁴ Interest credits are based on the 30-year United States Treasury bond rate which changes annually.

SDG&E provides the same traditional and Cash Balance Plans provided by SoCalGas. A traditional retirement benefit plan is provided for all union employees hired prior to July 1, 2003 and a Cash Balance Plan to all union employees hired on or after July 1, 2003. Non-union employees are subject to the Cash Balance Plan.

Pension cost estimates are prepared utilizing annual actuarial valuations prepared by WTW and includes the value of benefit obligations and minimum

³⁸⁴ Exhibit 216 at DSR-5.

required contributions.³⁸⁵ The valuations are performed in accordance with generally accepted actuarial principles.

The current funding policy plans for both utilities are based on costs for the minimum required contributions calculated in accordance with the Employee Retirement Income Security Act of 1974 (ERISA), the Pension Protection Act of 2006 (PPA), and as allowed by the Internal Revenue Code. According to Applicants however, the current funding methodology has led to a significant shortfall with respect to the amount of benefit payments that are actually made versus employee contributions for benefit payments. From 1999 to 2016, benefit payments exceeded contributions by approximately \$1,820 million for SoCalGas and \$690 million for SDG&E.³⁸⁶ Applicants also state that this shortfall increases long-term costs due to higher Pension Guaranty Corporation premiums and higher accrued interest costs.

Applicants thus propose a new funding policy that will fully fund pension benefits within seven years. The proposed funding would include the minimum annual service cost required by Accounting Standards Codification (ASC) 715-30 plus an amount that would fully fund the deficit over seven years. The amount would be adjusted if the minimum ERISA contributions are raised by law or if higher contributions are necessary to maintain an 85 percent Adjusted Funding Target Attainment Percentage (AFTAP). Contributions would be limited to keep plan assets from exceeding 110 percent of the pension liability as a result of the contribution. The pension liability would also be calculated according to

³⁸⁵ *Id.* at DSR-6.

³⁸⁶ Exhibit 216 at DSR-7 to 8.

Generally Accepted Accounting Principles (GAAP) and not according to PPA calculations. Applicants also propose continuation of their respective two-way pension balancing accounts (PBA) due to the variable nature of pension costs.

32.1.1. Positions of Intervenors

Comments to Applicants' pension proposals were provided by ORA, TURN, and Indicated Shippers.

ORA has no objections to Applicants' forecasts and requests regarding pension.

TURN agrees that the required minimum contributions should be changed but proposes that the GAAP Pension Expense be used as the annual contribution amount. Under GAAP, pension expense is the cost incurred for providing service to customers. TURN states that around \$116.950 million for SoCalGas and \$29.715 million for SDG&E are due from Applicants' proposed amortization of the pension benefit obligation (PBO) shortfall. TURN believes that using the GAAP Pension Expense as the contribution amount would eventually eliminate the pension shortfall over a longer period of time. As an alternative, TURN recommends that the pension shortfall be fully funded over 15 years instead of seven. TURN also recommends that Applicants' shareholders be required to contribute \$10 million for SoCalGas and \$5.3 million for SDG&E annually to address pension shortfalls because certain unilateral decisions such as awarding new benefits under the Voluntary Retirement Enhancement Program (VREP) result in additional pension costs.

IS states that the current funding policy is adequate but recommends that if Applicant's method is authorized by the Commission, that the pension shortfall be fully funded in 21 years instead of seven.

32.1.2. Discussion

Parties do not dispute that pension costs are necessary, and we agree that pension benefits form part of the total compensation offered by Applicants to their employees. From the testimony and briefs submitted by parties, it is clear and undisputed that Applicants are in compliance with the minimum annual contributions required by ERISA and the requirement that the annual contributions be no less than what is necessary to maintain an 85 percent AFTAP to ensure that their pension plans are fully funded. However, it is also clear that the above methods have resulted in deficits to Applicants' pension plans by approximately \$1,820 million for SoCalGas and \$690 million for SDG&E.

Applicants propose a change in the funding methodology that aims to fully fund the pension deficits that have resulted, and parties other than IS do not disagree. We disagree with IS and find it prudent and necessary to address the pension shortfall to ensure that Applicants' pension plans have sufficient funding to meet pension needs, to minimize long-term costs of funding the pension plans, and to establish a stable contribution pattern that keeps Applicants' pension plans fully funded.

The issue to be resolved is the appropriate funding methodology that best addresses the existing pension shortfall but also takes into account the reasonableness of costs and affordability of rates.

Applicants propose to increase contributions such that the pensions become fully funded within seven years. As an alternative to their main recommendations, TURN and IS propose that the period be 15 and 21 years respectively instead of the seven proposed by Applicants. TURN's main proposal however, is for annual pension contributions to be set at the GAAP Pension Expense amount which means using the costs actually incurred in

providing the pension benefits. TURN suggests that if pension contributions are set at actual service costs while maintaining the current minimum requirements discussed above in cases where actual costs are less than the current minimum requirements, then the pension deficits would be eliminated over time.

With respect to TURN's main proposal of using GAAP Pension Expense as the contribution amount, we agree with Applicants that this method does not address the current deficit and according to Applicants, would leave around \$304 million in existing unfunded pension obligations (combined for both SDG&E and SoCalGas) as unrecovered.³⁸⁷ The \$304 million represents existing unfunded obligations that were already recognized under GAAP Pension Expense but not recovered. In addition, the actual service costs do not include what Applicants refer to as special accounting events such as settlements, curtailments, and special termination benefits and these costs are not always appropriately reflected in basic GAAP Pension Expense.

Thus, we find Applicants' proposal of increasing contributions to eliminate the pension shortfall over a period of time is more appropriate. However, we find that Applicants' proposal to eliminate the pension shortfall over a period of seven years results in severe increases to pension costs. For TY2019 for example, \$116.950 out of \$202.830 million for SoCalGas and \$29.715 out of \$63.970 million for SDG&E are due from Applicants' proposed amortization of the PBO shortfall. As stated above, while we find it necessary to develop a funding mechanism that will address the PBO shortfall, we must also ensure that costs are reasonable and

³⁸⁷ Exhibit 219 at DR/YG-22 to 23.

that rates remain affordable. Thus, we find it more appropriate to spread out the costs of funding the PBO shortfall over a longer period of time.

TURN and IS alternate proposals recommend that costs to fund the pension shortfall be spread over 15 and 21 years respectively. IS's proposal is based on the difference between 65 years and the average age of SoCalGas retirement plan participants which is 44. We find IS's method to be more appropriate as it balances when the PBO shortfall must be fully funded by taking into account the time when most of the retirement plan participants will retire and keeping costs reasonable and rates affordable. However, we find that IS does not take into account that many employees opt for early retirement options that are available and retire earlier than age 65. And as Applicants provided, using 2017 data, SoCalGas employees are expected on average to retire within 15.42 years and within 13.86 years for SDG&E.³⁸⁸

We find it more appropriate to use the average age of retirement instead of 65 as the basis of time for which the PBO shortfall should be funded over time. Therefore, we find that Applicants' proposal to increase contributions such that the pensions become fully funded but within 14 years instead of seven years using the average age SoCalGas and SDG&E retirement plan participants are expected to retire.

Applicants argue that funding the PBO shortfall over a long period of time cause intergenerational inequities which means that ratepayers in the future would be made partially responsible for the current PBO shortfall. However, we find that any inequity that may result to future ratepayers is less severe than

³⁸⁸ Exhibit 219 at DR/YG-25.

requiring current ratepayers to fully fund the huge pension deficits over a short period of time. We also find that current ratepayers should not be made fully responsible for a pension deficit that occurred over time. In any case, we find it more appropriate to spread out costs over a longer period using the average retirement age of Applicants' employees.

With respect to TURN's proposal to make Applicants fund a certain portion of the PBO shortfall, we find that TURN did not fully support and establish its allegation that Applicants made discretionary unauthorized retirement incentive payments which increased pension liabilities. With respect to the VREP, we find that this program affected the timing for when pension distributions would occur but did not necessarily add additional amounts to be distributed. Thus, we find that there is insufficient basis to require Applicants to be partially responsible for the PBO shortfall and that they have complied with the funding requirements required by law.

In sum, Applicants proposal to increase contributions such that their respective pension funds become fully funded should be accepted with the modification that the pension funds be fully funded within 14 years instead of the proposed seven years. Applicants should revise their proposed TY2019 pension costs based on the above modification. We also direct SoCalGas and SDG&E in its next GRC application to provide testimony on the current funding levels and the outstanding balance of the PBO so we can assess whether any modifications to the timing require adjustment. We also find Applicants' request to continue their respective two-way PBAs to record pension costs reasonable and should be approved. We agree that pension costs are difficult to predict and costs are subject to variables that are beyond Applicants' control. Thus, we find

it reasonable to continue the two-way balancing account treatment for pension costs.

32.2. PBOP

SDG&E and SoCalGas provide post-retirement health and life insurance benefits to retirees, and survivors. Benefits include medical, dental, and vision insurance coverage, mental health and substance abuse coverage, and life insurance. Effective December 1, 2009, PBOP benefits include a health reimbursement account for qualified medical expenses during retirement. In 2016, both utilities also offered a voluntary retirement enhancement program to eligible employees and employees that accepted were credited with an opening balance for reimbursement of qualified medical expenses upon retirement. No other expenses or accruals are due after the opening balance credits. Retiree contributions depend on date of retirement, age, years of service, chosen plans, and whether they were union or non-union employees.³⁸⁹

The TY2019 forecasts for PBOP are \$0 for SoCalGas and \$1.430 million for SDG&E. In comparison, 2016 recorded costs for PBOP were \$0.271 million for SoCalGas and \$2.357 million for SDG&E.

PBOP costs and estimates are prepared by the utilities' actuary, WTW, and includes the value of benefit obligations and minimum required contributions.³⁹⁰ According to Applicants, the valuations are performed in accordance with generally accepted actuarial principles. PBOP expenses include costs for current retirees and an allocation of costs for current employees who are expected to

³⁸⁹ Exhibit 216 at DSR 29 to 32.

³⁹⁰ *Id.* at DSR-32.

access benefits in their future retirement and costs are determined in accordance with Financial Accounting Standard (FAS) 715-60.³⁹¹ As shown above, no costs are projected for SoCalGas' PBOP for TY2019 based on valuations prepared by WTW.

Applicants' state that BPOP expenses are difficult to project due to variables that fluctuate such as benefit utilization, healthcare and cost escalation, PBOP plan asset returns, interest rates, and plan design and request that the current PBOP balancing accounts (PBOPBA) be continued. In addition, Applicants request to implement an annual true-up for the PBOPBAs as opposed to waiting until the next GRC.

32.2.1. Positions of Intervenors

ORA is the only other party that provided comments to Applicants' PBOP requests and does not take issue with either SDG&E's or SoCalGas' TY2019 forecasts and the continuation of the two-way PBOPBAs being requested.

32.2.2. Discussion

We reviewed Applicants' TY2019 forecasts for PBOP and find them to be reasonable and supported by the evidence. We also have no objections to the benefits provided under the PBOP as these are standard benefits provided to retirees and have been included in Applicants' prior GRCs. PBOP costs continue to be determined in accordance with FAS 715-60. We also find that the request to continue the two-way PBOPBAs for both SoCalGas and SDG&E to be reasonable and appropriate as PBOP costs are determined by variables not subject to Applicants' control and costs can fluctuate over time. Therefore, we find that the

³⁹¹ *Id.* at DSR-32 to 33.

TY2019 forecasts of \$0 for SoCalGas and \$1.430 million for SDG&E and the requested continuation of the two-way PBOPBAs for both utilities should be approved. We also have no objections to an annual true-up of the PBOPBAs as proposed by Applicants considering the fluctuating costs for PBOP that may occur annually which could lead to large discrepancies between actual and forecast costs over a three-year period.

33. Human Resources, Safety, and Worker's Compensation & Long-Term Disability

This section will discuss the TY2019 forecasts for Human Resources (HR), Safety and Worker's Compensation, and Long-Term Disability.

33.1. SoCalGas

Most of the forecast costs for TY2019 are for O&M with one capital project request relating to Business Optimization. The total O&M forecast for TY2019 is \$46.539 million which is \$10.671 million higher than 2016 adjusted, recorded costs. For capital, the request is \$0.300 million in 2017, \$0.491 million in 2018, and \$0.791 million in 2019.

The forecast includes \$1.143 million in savings from FOF and excludes costs from the Aliso Canyon gas leak incident. Certain costs are associated with mitigating RAMP risks identified in the RAMP Report. These are employee, contractor, customer, and public safety and workforce planning. Total RAMP costs are \$14.466 million with \$7.292 of those representing incremental RAMP costs for TY2019. Incremental costs include risk mitigation activities and programs relating to driver safety, enhanced drug and alcohol testing and monitoring, verifying safety history of contractors, knowledge management, leadership training, and succession planning.

33.1.1. Non-Shared O&M

The total forecast for non-shared O&M costs is \$44.839 million³⁹², which is \$10.634 million higher than base year adjusted, recorded costs. Most of the increased costs are from the Human Resources Department and in particular the SCG Director of Safety & Wellness which accounts for \$6.012 which, according to SoCalGas, is due to the implementation of activities outlined in Chapter 2 of the RAMP Report to mitigate Employee, Contractor, Customer, and Public Safety risks.

33.1.1.1. CEO, President & COO, Chief HR, and CAO

This cost center includes the offices of the CEO, President & Chief Operating Officer (COO), Chief HR, and Chief Administrative Officer (CAO). The forecast for TY2019 is \$2.758 million which remains unchanged from base year costs. A base year forecast was utilized because the base year reflects the expense level associated for this group. This group provides executive leadership as well as direction in providing safe and reliable service to customers. The group also provides strategic direction and leadership and directs the activities of SoCalGas for this section.

33.1.1.2. Human Resources Department

The HR Department is responsible for attracting, developing, and retaining employees with the experience, qualifications, and skills necessary to ensure the safe, reliable delivery of natural gas services to SoCalGas'

³⁹² Revised from \$44.839 million to \$49.252 million in the Update Testimony (Exhibit 514) at Attachment H.

customers.³⁹³ The HR Department is made up of several departments and the table below shows the TY2019 forecast for each as well as the increases over base year adjusted, recorded costs. All forecasts were made utilizing base year plus adjustments.

HR Department	TY2019 Forecast	Increase from 2016 costs
Business Partners	\$1,943,000	\$81,000
Performance Management & Organizational Strategy	\$1,532,000	\$372,000
HR Services	\$5,186,000 ³⁹⁴	\$1,273,000
Labor Relations	\$1,025,000	\$204,000
Safety & Wellness	\$10,509,000	\$6,012,000
Organizational Effectiveness	\$3,823,000	\$1,663,000

Business Partners

Primary point of contact on strategic resources issues for leadership and provides interpretation of company policies.

Performance Management and Organizational Strategy

Acts as an internal consultancy in developing processes to measure and monitor performance of the workforce. The department also provides advanced statistical analysis and simulation modeling.

HR Services

Includes staffing, research and workforce planning, operations, compensation, and employee care services.

³⁹³ Exhibit 255 at MG-13.

³⁹⁴ Revised from \$5,186,000 to \$5,218,000 in the Update Testimony (Exhibit 514) at Attachment H.

Labor Relations

Responsible for labor strategy, union relations, collective bargaining agreements, contract administration, grievances, mediations, arbitrations, and actions by the National Labor Relations Board.

Safety & Wellness

Responsible for the health and safety of employees and ensures compliance with all required health and safety regulations. The department also provides education and training to help ensure that the workplace is incident-free. The department also promotes and health and wellness by administering education and mental health programs.

Organizational Effectiveness

Provides leadership, organizational, and employee development programs, instructional design, and knowledge transfer.

33.1.1.3. Worker's Compensation & Long-Term Disability

The TY2019 forecast for Workers' Compensation & Long-Term Disability is \$18.063 million³⁹⁵ which is higher by \$1.029 million³⁹⁶ from 2016 adjusted, recorded expenses. SoCalGas utilized a three-year historical average methodology and a non-standard escalation factor for its forecast on workers' compensation and a base year methodology for long-term disability plus escalation. SoCalGas explains that the higher costs are due primarily to labor

³⁹⁵ Revised from \$18.063 million to \$22.444 million in the Update Testimony (Exhibit 514) at Attachment H.

³⁹⁶ Revised from \$1.029 million to \$5.410 in the Update Testimony (Exhibit 514) at Attachment H.

and non-labor escalation and medical escalation and that the forecast already includes \$1 million in expected savings from FOF.

Workers' Compensation are mandated benefits provided to California employees who are injured on the job. For long-term disability, SoCalGas' program pays 60 percent of pre-disability earnings to qualified employees.

33.1.2. Position of Intervenors

OSA, ORA, and TURN provided comments to SoCalGas' non-shared O&M costs.

OSA recommends that a comprehensive approach to safety culture assessment should be applied and that contractors should be included.

ORA recommends reductions of \$147,000 for HR Services, \$539,000 for Safety & Wellness, and \$107,000 for Organizational Effectiveness based on reduced funding for RAMP incremental activities. ORA states that a more conservative estimate is appropriate until SoCalGas has had more years of recorded expenses for the new programs being proposed.

TURN recommends a reduction of \$144,000 to Labor Relations because it recommends exclusion of \$34,000 associated with a post-Aliso Canyon incident return-to-work schedule and because the amounts requested for job leveling activities are much higher than the base year and prior years.

TURN also recommends a total reduction of \$3.984 million for Safety & Wellness. TURN recommends a disallowance of \$136,000 associated with returning work that was temporarily re-assigned to the Aliso Canyon incident because the work needed was performed even without the re-assigned labor. TURN also recommends disallowance of \$2.165 million for the Interactive Driver Safety Program and \$1.683 million for Defensive Driver Training and In-Vehicle Refresher Course. TURN argues that SoCalGas did not demonstrate tangible

benefits to ratepayers for these programs. Alternatively, TURN recommends reduced funding of \$1.2 million for the Interactive Drive Safety program and 25 percent of the funding requested for the In-Vehicle Instruction program.

TURN also recommends a reduction of \$542,000 to Organizational Effectiveness because of returning work from the Aliso Canyon incident and because the Director Development program is speculative and the costs were not justified.

Finally, both ORA and TURN object to the 7.0 percent medical premium escalation rate used by SoCalGas for workers' compensation with ORA recommending a 4.25 percent rate and TURN recommending 6 percent.

33.1.3. Discussion

In its rebuttal testimony, SoCalGas agrees with OSA that a multi-method framework should be utilized to comprehensively assess safety culture but states that this as well as integrating additional components to the framework should be done gradually so that employees will better understand and take ownership of the outcome. SoCalGas also agrees that contractors should be included in safety culture assessments and plans to explore effective ways in which to do so. Finally, SoCalGas also agrees that additional questions should be added to the National Safety Council survey in order to continue to improve it as a survey tool. We agree with the issues and concerns raised by OSA but also agree with the approach presented by SoCalGas in order to address the concerns raised by OSA. We find that the framework to assess safety culture should continue to improve and evolve. In its next GRC application, SoCalGas should include a report in the form of testimony that details the studies conducted, findings made, and steps taken regarding a multi-method framework to assess safety culture and including contractors in safety culture assessments.

With respect to all the post-Aliso Canyon incident return to work issues raised by TURN, we find that the work re-assignments that were prioritized to perform necessary work in connection with the Aliso Canyon gas leak incident was temporary in nature and was not meant to re-organize the work being performed by the departments from where the labor was extracted. TURN argues that regular work was performed nonetheless despite the FTEs re-assigned but we find that this does not address whether certain work was deferred or whether other employees simply covered for the re-assigned labor on a temporary basis. It also does not mean that the work being performed disappeared or was reduced. Thus, we find it reasonable to add back labor costs for returning FTEs that were temporarily re-assigned to perform work associated with the Aliso Canyon gas leak incident. The labor costs that are being authorized pertain to prospective work that will be performed by returning employees. If any work had been deferred, then these must be performed within the labor costs that are being authorized in this decision and on top of the regular work that the regular and returning employees regularly perform.

On the issue of job leveling, while we agree that the costs incurred to update the job level system are reasonable in order to ensure that job pay levels are appropriate, we find that SoCalGas did not provide sufficient evidence to explain why job leveling needs to occur every year especially with respect to existing jobs. It is unclear from the testimony presented why jobs that have just undergone an initial leveling process need to undergo the same process each year. Instead, we find it more reasonable for job leveling to occur periodically absent other evidence that shows otherwise. Also, as pointed out by TURN, during periods in which job leveling occurs, not all jobs are updated which supports the conclusion that leveling only needs to occur periodically.

Therefore, we agree with TURN that it is more appropriate to treat the projected incremental cost of \$170,000 for TY2019 as a non-recurring cost and spread the cost over the three years included in the GRC cycle. Therefore, we find it reasonable to reduce the requested amount for Labor Relations by \$113,000 resulting in an amount of \$0.912 million that should be approved.

Regarding TURN's recommended disallowance of costs for the Interactive Driver Safety Program and Defensive Driver Training and In-Vehicle Refresher Course, first, we do not disagree that the programs may be effective in reducing vehicle incidents that are within a driver's control. However, as TURN pointed out, the programs are to be applied to all of SoCalGas' employees and many employees have job functions such as office work, that do not require them to drive a motor vehicle as part of their job functions. While many employees may ultimately drive a vehicle such as to and from work, we find that it is necessary in this case to distinguish between driving per se and driving as part of an employee's work responsibilities. We find that ratepayers should not be held responsible for costs to mitigate driving incidents where driving is not part of an employee's work in providing safe and reliable natural gas and electric services to customers. Moreover, these programs as applied to such employees benefit the company much more than any benefit that may accrue to ratepayers. As such, we find that shareholders should be primarily responsible for these programs with respect to employees that are not required to drive as part of their job function. Since it is not clear what percentage of employees are required to drive as part of their work and because some residual benefits do accrue to ratepayers, in this case we find that it is reasonable to allow SoCalGas to recover 50 percent of the costs for these programs. Therefore, we find it reasonable to disallow \$1.082 million for the Interactive Driver Safety Program and \$0.842

million for Defensive Driver Training and In-Vehicle Refresher Course. This results in an amount of \$8.585 million that should be authorized for Safety & Wellness. And we find the above amount to be more reasonable than TURN's alternative recommendation

The above discussion addresses ORA's concern about reduced funding for RAMP-related costs for Safety & Wellness. For ORA's recommended reductions in RAMP-related costs for HR Services and Organizational Effectiveness, we find that ORA does not challenge the necessity of any of the actual programs, the individual forecasts, or the forecast methodology utilized for the RAMP-related costs. Rather, ORA seems to base its recommendation on the low-end of the forecast range that was presented in the RAMP Report. However, the mitigation activities suggested and the cost ranges presented in the RAMP Report are only meant to inform the actual requests that are being made in the GRC. Thus, the actual requests made in the GRC may vary since the RAMP Report was subject to review, comments, and suggestions from SED, parties in the RAMP proceeding, and the Commission. We find that SoCalGas presented sufficient testimony to support the necessity and reasonableness of costs for the RAMP-related programs ORA objects to. Based on the above, we find that ORA's request to reduce funding for the RAMP-related costs under HR Services and Organizational Effectiveness should be denied.

Regarding the medical premium escalation rate to be applied, we reviewed SoCalGas' proposal as well as the alternative recommendations by ORA and TURN. TURN's recommendation is based on the its own medical escalation figures for 2018 and 2019 while ORA used the average between the Kaiser Family Foundation Health Benefits Survey of average family premium increase for employers of 3.0 percent and the projection by the Price Waterhouse Cooper

Health Research Institute of 6.5 percent. However, we find that the medical trend forecast prepared by Willis Towers Watson is more reasonable to apply because the forecast was prepared specifically for SoCalGas taking into account workforce demographics, historical utilization data, and medical plan design³⁹⁷ and is more reflective of SoCalGas' medical premium costs. SoCalGas also cited additional factors that contribute to an upward trend of medical costs compared to prior years such as dependent coverage up to age 26, the prohibition of annual and lifetime coverage limits, and the requirement to provide immunizations and preventative services with no cost sharing from employees. Therefore, we find that SoCalGas' proposed medical premium escalation rate of 8.0 percent for 2018 and 7.0 percent for 2019 is more appropriate and should be authorized.

With respect to the unopposed costs, we find that SoCalGas presented sufficient evidence to establish the necessity of the activities to be funded by the requested costs and do not object to the forecast methodologies that were utilized.

To summarize, we find that SoCalGas' non-shared O&M forecasts should be approved except for Labor Relations which should be reduced to \$0.912 million and Safety & Wellness which should be reduced to \$8.585 million. This leads to a total amount of \$49.284 million compared to the initially requested amount of \$44.871 million after applying adjustments to non-shared HR Services and worker's compensation reflected in SoCalGas' update testimony.³⁹⁸

³⁹⁷ Exhibit 208 at DSR-30.

³⁹⁸ Exhibit 514.

33.1.4. Shared O&M

Shared Services is composed of two cost categories which are HR Diversity and HR Services. The total forecast for TY2019 is \$1.700 million³⁹⁹ which is close to base year level of spending of \$1.663 million. SoCalGas utilized a base year forecast methodology because projected costs are expected to remain around base year levels.

33.1.4.1. HR Diversity

HR Diversity is responsible for developing and directing the strategic business objectives for managing workplace diversity including directing the diversity strategic plan, policies, and programs. The department also develops and conducts training on prevention of workplace harassment, discrimination, and diversity related issues. The forecast for HR Diversity is \$0.557 million.

33.1.4.2. HR Services

HR Services is composed of Employee Care Services (ECS) Reporting, ECS Operations, and ECS Regulations & Training. The total forecast is \$1.143 million.⁴⁰⁰

ECS Reporting operates and maintains the electronic systems used to manage ECS work. ECS Operations provides administrative support to ECS personnel. ECS Regulations & Training provides training and audits the performance of department personnel

³⁹⁹ Revised from \$1.700 million to \$1.668 million in the Update Testimony (Exhibit 514) at Attachment H.

⁴⁰⁰ Revised from \$1.143 million to \$1.111 million in the Update Testimony (Exhibit 514) at Attachment H.

33.1.4.3. Discussion of Shared Services

ORA is the only intervenor that provided comments to the shared services costs and does not take issue with SoCalGas' forecasts.

We reviewed SoCalGas' proposed costs and find the forecasts and requested amounts to be reasonable. Projected costs are around base year levels. Therefore, we find that the requested amount of \$1.668 million should be approved.

33.1.5. Capital

The single capital project requested is for Business Optimization. The project aims to replace the existing 15-year old software for the Employee Care Services iVOS Claims System.

ORA accepts the business justification for the project and does not object to the projected costs. We find that the project is necessary as the current software will be phased out in the next few years.⁴⁰¹ The new software will also have enhanced capabilities, supports customization, and will be more user friendly. We also find the projected costs to be reasonable.

Therefore, we find that the forecast amounts of \$0.300 million in 2017, \$0.491 million in 2018, and \$0.791 million in 2019 should be approved.

33.2. SDG&E

SDG&E's TY2019 forecast is \$19.164 million which is \$2.164 million higher than 2016 adjusted, recorded costs. All costs are for O&M. The forecast includes \$0.125 million in savings from FOF. Certain costs are associated with mitigating RAMP risks identified in the RAMP Report. These are employee, contractor,

⁴⁰¹ Exhibit 255 at MG-41.

customer, and public safety and workforce planning. Total RAMP costs are \$0.466 million with \$0.330 million representing incremental RAMP costs for TY2019.

33.2.1. Non-Shared O&M

Total non-shared costs forecast for TY2019 is \$15.187 million⁴⁰² which is \$2.305 million higher than base year costs. A large part of the increase of \$2.344 million⁴⁰³ is associated with Safety, Wellness and ECS. The table below shows the various non-shared forecasts for the different departments. All forecasts utilized the base year methodology, except for long-term disability and workers' compensation under the Safety, Wellness and ECS department which were forecast using a zero-based methodology.

Non-shared O&M	TY2019 Forecast
Chief HR and CAO	\$597,000
Safety, Wellness and ECS	\$7,518,000
Diversity and Workforce Management	\$1,986,000
Organizational Effectiveness	\$2,178,000
Employee Communications	\$338,000
HR Diversity	\$175,000
President and COO Offices	\$2,395,000
Total Non-Shared	\$15,187,000

Chief HR and Chief Administrative Officer

Provides leadership and strategic direction for HR and Operations Support and Environmental Services and ensures that employees possess the qualifications, experience, and skills necessary to perform their job functions.

⁴⁰² This amount was revised from \$14.558 million after applying an adjustment to Worker's Compensation of \$0.629 million reflected in SDG&E's update testimony in Exhibit 514.

⁴⁰³ This amount is higher than the total increase because of reduced costs in other departments.

Safety, Wellness, and ECS

Responsible for safety, health, and well-being of employees and contractor safety. The department also handles long-term disability leaves, work accommodations, non-industrial leaves, return to work programs, and workers' compensation.

The Diversity and Workforce Management

Department is responsible for staffing and verifying a candidate's suitability for employment, relocation, and the HR information systems that provides operations and tactical reporting and technology support.

Organizational Effectiveness

Provides development programs and is responsible for talent management and development, organizational design, people research, and workforce planning.

Employee Communications

Develops the communication strategy and implementation and keeps employees informed about SDG&E's strategic goals, priorities, commitments, position regarding the environment, community service, financial performance, operational updates, employee benefits, and other important information.

HR Diversity

Develops and directs the strategic business objective for managing workplace diversity.

President and COO Offices

Provide leadership, guidance, and direction to employees and is responsible and accountable for SDG&E's performance.

33.2.2. Shared O&M

Total shared costs forecast for TY2019 is \$4.606 million which is \$0.488 million higher than base year costs. The table below shows the various shared forecasts for the different departments that perform shared services functions. All forecasts utilized the base year recorded method.

Shared O&M	TY2019 Forecast
Field Safety	\$971,000
Labor Relations and Business Partner	\$1,665,000
Safety Compliance	\$601,000
ECS and Wellness	\$1,061,000
Manager Analysis & Workforce Planning	\$308,000
Total Shared	\$4,606,000

Field Safety

Provides support of field safety compliance audits, program support, communications, management, and statistical analysis including incident investigation, correction, and prevention.

Labor Relations

Responsible for labor strategy, union relationships, collective bargaining agreement negotiations, contract administration, grievances, mediations, arbitrations, and National Labor Relations Board actions. Business Partner is the primary point of contact for HR issues and ensures that HR plans align with business plans.

Safety Compliance

Primarily responsible for compliance with safety regulations and establishes and manages safety programs, policies, and guidelines to ensure employee safety.

ECS

Handles long-term disability leaves, work accommodations, non-industrial leaves, and return to work programs, and workers' compensation.

Wellness

Manages and administers the employee assistance program.

Manager Analysis & Workforce Planning

Performs research, analysis, and workforce planning services and ensures compliance with legal, professional, and regulatory issues related to personnel selection, testing, and promotion.

33.2.3. Positions of Intervenors

OSA, ORA, and TURN provided comments and recommendations to SDG&E's proposals.

OSA recommends that SDG&E's safety culture assessment take a more comprehensive approach, incorporate contractors in SDG&E's assessment, incorporate questions that reveal safety perceptions, and evaluate improvement strategies and follow best practices.

For non-shared costs, ORA recommends a 4.25 percent medical escalation rate resulting in a reduction of \$190,000 for the workers' compensation portion of the Safety, Wellness and ECS department and a reduction of \$192,000 for the RAMP portion of Organizational Effectiveness. ORA states that a more conservative estimate is appropriate until SDG&E has had more years of recorded expenses for the new programs being proposed. ORA does not object to any of the shared services forecasts.

TURN argues that the Edison Electric Institute (EEI) membership dues should be funded by shareholders. TURN also recommends a 6.0 percent medical premium escalation rate.

33.2.4. Discussion

OSA makes similar recommendations regarding assessment of safety culture and inclusion of contractors in safety culture assessments as it did in the SoCalGas section which we discussed in section 33.1.3. SDG&E also agrees with many of the recommendations made by OSA but suggests that a multi-method framework should be incorporated gradually. SDG&E also plans to come up with effective ways to include contractors in safety culture assessments and agrees that additional questions should be added to the National Safety Council survey. We have no objections to SDG&E's approach in addressing OSA's concerns and find that as part of its next GRC application, SDG&E should include a report in the form of testimony that details the studies conducted, findings made, and steps taken regarding a multi-method framework to assess safety culture and including contractors in safety culture assessments.

ORA raises the same arguments regarding the RAMP-related costs for Organizational Effectiveness as it did for SoCalGas' Organizational Effectiveness department and we make the same findings and conclusions in denying ORA's recommendation as discussed in 33.1.3 with respect to this issue. In addition, SDG&E provided additional details regarding the RAMP-related training programs⁴⁰⁴ that will be conducted which further identify the benefits of these programs and further support the necessity thereof.

ORA and TURN also raise the same issues and make the same respective recommendations regarding the medical premium escalation rate as it did for SoCalGas. Similarly, we make the same findings and conclusions as we did in

⁴⁰⁴ Exhibit 364 at TT-17 to 18.

the SoCalGas section and find that the medical trend forecast prepared by Willis Towers Watson for SDG&E is more reasonable to apply because the forecast was prepared specifically for SDG&E taking into account workforce demographics, historical utilization data, and medical plan design and is more reflective of SDG&E's medical premium costs.

With respect to TURN's objections concerning membership dues for the EEI, the EEI is an association of shareholder-owned electric utilities in the United States and provides public policy leadership, industry data, strategic business information, conferences and forums, and other products and services to its members. According to SDG&E, "the EEI brings SDG&E employees together with peers and colleagues from other companies in the industry to perform collective activities that are not regularly performed by the individual companies on a full-time basis, such as benchmarking studies, industry surveys, and sharing best practices."⁴⁰⁵ From the above, we agree with SDG&E that membership in the EEI provides benefits to ratepayers because of the industry-specific information, training, and database that may be obtained as well as the sharing of best practices and information about research and studies made by experts and consultants.

With respect to the membership costs, SDG&E presented copies of invoices from EEI for 2016 and 2017 which states that the portion of membership dues spent of activities relating to lobbying is 13 percent. In D.14-08-032, the Commission disallowed recovery of 43.3 percent of EEI dues based on data audited by the National Association of Regulatory Utility Commissioners that

⁴⁰⁵ SDG&E and SoCalGas Opening Brief at 525.

was presented by TURN.⁴⁰⁶ In this case however, TURN does not present any data or alternate means of calculating the portion of membership dues that is to be excluded because they are spent on activities that do not benefit ratepayers such as lobbying. TURN suggests other activities that may be performed which may be subject to exclusion but does not identify specific activities or a way to calculate the amounts that may correspond to these if they are being performed. Thus, the best evidence available here are the membership invoices that specify that 13 percent of the membership dues are spent on lobbying. With respect to the incremental amount requested for TY2019, SDG&E provides that the amount of \$174,000 represents incremental EEI membership dues of \$200,000 less the 13 percent for lobbying activities. Based on all of the above, we find it reasonable not to make reductions to the requested amounts for EEI membership dues.

To summarize, we find SDG&E's requested and adjusted amount of \$19.793 million for non-shared and shared O&M costs to be reasonable and should be approved.

34. Administrative & General

The Administrative & General (A&G) section for both SoCalGas and SDG&E includes the divisions of Accounting and Finance (A&F), Legal, Regulatory Affairs, and External Affairs. Costs include both shared and non-shared costs but the discussion for this section will not distinguish between shared and non-shared costs. Costs for Meals and Entertainment are normally included in this section but as discussed in section 34.3 below, both SoCalGas

⁴⁰⁶ D.14-08-032 at 261 to 262.

and SDG&E are voluntarily waiving recovery of estimated costs for Meals and Entertainment in this GRC cycle on a non-precedential basis.

34.1. SoCalGas

The total TY2019 forecast for A&G is \$35.305 million⁴⁰⁷ which is \$3.780 million less than adjusted, recorded costs for 2016. The lower costs forecast for TY2019 are due to lower costs forecast for the A&F Division and from FOF savings of \$0.559 million which are incorporated into the forecasts. Pursuant to D.16-06-054, costs relating to the Aliso Canyon gas leak incident are not included in the forecast and have been removed from historical information.

Certain activities in this section relate to risk mitigation concerning Records Management, which is one of the key risks identified in the RAMP Report. To address this risk, SoCalGas plans to hire a third-party records management expert to conduct a gap assessment between current and leading records management policies and practices. The total cost for RAMP-related activities is \$0.865 million.

34.1.1. A&F Division

The A&F Division performs the day-to-day financial and accounting functions at SoCalGas. The division includes the following departments: VP for A&F; Accounting Operations; Accounting Systems and Compliance; Incident Support Analysis; Finance; Financial and Operational Planning; Controller; Claims Management; and Claims Payments and Recovery. The total forecast for TY2019 is \$21.873 million using a five-year historical average as a basis. The table below shows the various departments that comprise the A&F Division and

⁴⁰⁷ Revised from \$35.305 million to \$35.286 million in the Update Testimony (Exhibit 514) at Attachment H.

the forecast costs for each. Following the table, we briefly describe the major function of each department.

A&F Division	TY2019
VP Accounting & Finance	\$352,000
Accounting Operations	\$3,754,000
Accounting Systems & Compliance	\$1,545,000
Incident Support Analysis	\$1,101,000
Finance	\$1,437,000
Financial & Operational Planning	\$3,819,000
Controller	\$885,000
Claims Management	\$1,579,000
Claims Payments & Recovery	\$7,401,000
Total	\$21,873,000

VP for A&F

Provides executive oversight and supports business needs.

Accounting Operations

Responsible for the gas plant portion of rate base accounting, capitalization of cost accounting for gas assets, new business accounting, fixed asset management, and billable project accounting.

Accounting Systems and Compliance

Oversees financial systems, provides administration and compliance with Sarbanes-Oxley, establishes company-wide overhead allocation rates, and administers the affiliate compliance program.

Incident Support Analysis (ISA)

A new department that will be responsible for identifying historical major incidents and develops proactive response plans to support mitigation measures.

Finance

Performs a wide variety of financial and regulatory accounting functions and is primarily responsible for analyzing new projects, technology, and initiatives.

Financial and Operational Planning

Develops the one and five year financial plans of SoCalGas.

Controller

Provides oversight and guidance related to financial and accounting services.

Claims Management

Responsible for investigating claims, documenting claims information into a database, determining company or third-party liability, and resolving claims.

Claims Payments and Recovery

Responsible for net payments for third-party property damage, injury to persons, and recovery of claims.

34.1.2. Legal Division

The Legal Division provides a wide variety of legal services. This includes regulatory legal matters, civil litigation, legal advice on loss prevention, commercial and business disputes, commercial contracts, environmental compliance and litigation. The Division also includes administrative staff and costs for outside counsel for matters that require special skills or highly complex matters. The forecast for TY2019 is \$6.968 million using a five-year average.

34.1.3. Regulatory Affairs Division

The Regulatory Affairs Division manages compliance with federal, other state agencies, and Commission regulations. This includes management of proceedings, issues, and other regulatory matters. The Division includes the following departments: Director of Regulatory Affairs; Regulatory Tariffs and Information; Case Management; Gas Rates and Analysis; Gas Forecasting and Analysis; and GRC and Revenue Requirements. The table below shows the forecasts for each department followed by a brief description of the major

function of each department. The forecast for TY2019 is \$4.488 million using a five-year average.

Regulatory Affairs Division	TY2019
Director of Regulatory Affairs	\$215,000
Regulatory Tariffs and Information	\$656,000 ⁴⁰⁸
Case Management	\$1,094,000
Gas Rates and Analysis	\$322,000
Gas Forecasting and Analysis	\$877,000
GRC and Revenue Requirements	\$1,304,000
Total	\$4,488,000

Director of Regulatory Affairs

Oversees and manages various departmental functions and the development and implementation of regulatory policies and business objectives.

Regulatory Tariffs and Information

Responsible for filing advice letters and responding to protests and draft resolutions, maintaining and developing tariff schedules and providing guidance on regulatory compliance with tariffs.

Case Management

Coordinates participation in regulatory proceedings and related activities and compliance with directives and requirements.

Gas Rates and Analysis

Provides policy support, cost-based rate design for gas, and coordination for use in business development and regulatory proceedings.

⁴⁰⁸ This total reflects changes from the Update Testimony. The original amount was \$676,000.

Gas Forecasting and Analysis

Analyzes economic data, develops demand and price forecasts, and provides analysis for business development and regulatory proceedings.

GRC and Revenue Requirements

Responsible for management of GRC and other major proceedings before the Commission.

34.1.4. External Affairs Division

The External Affairs Division provides representation before community leaders and elected officials, manages and coordinates external communications with a broad set of stakeholders including media, government agencies, community organizations, elected officials, and members of the public, and promotes community relations. The TY2019 forecast for this division is \$1.976 million using a five-year average. This is exclusive of certain functions relating to regional public affairs and energy and environmental affairs which are included in other sections of the decision.

34.1.5. Positions of Intervenors

ORA and TURN provided comments on these forecasted costs.

ORA opposes all funding for the ISA department because SoCalGas did not present any studies to support the creation of this new department. ORA also recommends a reduction of \$100,000 to the Accounting Systems and Compliance department because SoCalGas did not explain how it developed the range of costs related to records management and SoCalGas' forecast of \$200,000.

TURN recommends two base year adjustments. The first is a reduction of \$22,000 associated with club dues and chamber of commerce dues because these are charitable contributions as opposed to operating expenses. The second is a reduction of \$64,000 for clothing and gear or specifically, giveaways and other

materials containing SoCalGas' logo (other than for uniforms, hard hats, etc.) as these expenses are largely promotional and image building and should not be paid for by ratepayers.⁴⁰⁹

34.1.6. Discussion

We reviewed SoCalGas' TY2019 forecasts in this section by examining the testimony presented, the proposed forecasts and forecast methodologies, recommendations and objections by parties, and arguments raised in briefs. Many of the activities that are included in the forecasts are activities that have been approved in prior GRCs and we find these to be reasonable and necessary. We have no objection to the forecast methodology which utilized the five-year historical average as the basis for the forecast because many of the divisions and activities have been in existence for a long period of time and costs are subject to year-to-year fluctuations because of new programs or because of certain activities such as the GRC application filing which occurs every three years. We also find the proposed costs to be reasonable which overall are less than base year recorded costs.

We find the RAMP-related activities proposed to be reasonable and aimed at addressing mitigation of risks concerning Records Management. ORA requests a reduction of \$100,000 to the \$200,000 requested by SoCalGas for the hiring of records management consultants as part of proposed mitigation efforts. However, we find that SoCalGas sufficiently explained the basis for the cost estimate. In a response to ORA's data request, SoCalGas explains the criteria utilized to develop the forecast and that it utilized a prior cost assessment by an

⁴⁰⁹ Exhibit 494 at 75 to 77.

outside company to determine the low end of the forecast.⁴¹⁰ The \$200,000 represents the midpoint between the high-end of the forecast and the low end of the forecast. SoCalGas also explains that this mitigation has a certain degree of uncertainty with respect to the range of costs and we find it reasonable to accept the midpoint between the low and high-end of the forecast range.

ORA opposes funding for the ISA department which is a new program to create a team that will specifically focus on major incident preparedness and response activities. From our review, we find that SoCalGas provided sufficient evidence to support the need for the ISA department. SoCalGas explained the need for the ISA department as well as the underlying activities that will be performed in testimony and in its workpapers.⁴¹¹ SoCalGas also explained that the amounts requested are for ten staff members and non-labor costs. SoCalGas further explained that the salaries for the ten staff members were derived using the mid-range salary of the Market Reference Ranges⁴¹² pay band for these positions. Based on the foregoing, we find that the requested amount for the ISA department was supported by testimony, contrary to ORA's claim, and that the requested costs are reasonable.

With respect to TURN's recommended adjustments, we find that reasonable memberships in certain clubs and chamber of commerce groups help foster SoCalGas' relationships with local businesses, chamber of commerce groups, and the local community. These memberships also help SoCalGas in

⁴¹⁰ Exhibit 320, Appendix A.

⁴¹¹ Exhibit 318 at SL-14, Exhibit 319 at 26, and Exhibit 320 at RG-3 to 6.

⁴¹² The Market Reference Range is based on the average actual paid salary in the external labor market according to salary surveys.

keeping abreast of developments and issues of concern in business and local communities within its service territory. The memberships also add another means of communication with some of its stakeholders. We also find the amount in question to be reasonable and not excessive. Thus, we find that it is reasonable not to remove the \$22,000 associated with club dues and memberships; however, SoCalGas elected to remove \$20,635 of these costs in the Update Testimony, Exhibit 514 at H-1, as \$1,365 was already removed in Exhibit SCG-32-WP, workpaper 2HR0012. On the issue of giveaways and other materials in the amount of \$64,000, we find that in this case, which perhaps differs with the findings made in D.14-08-032,⁴¹³ the materials and giveaways were used in conjunction with customer events to create awareness of customer programs and services. We find that the logo items and clothing were not utilized primarily as promotional or advertising materials but rather, were used as ways and means to enhance and maintain communication with customers and to ensure that they have knowledge and access to available programs and services that they can avail themselves of. Therefore, we find that no adjustment is necessary to remove these costs from 2016 expenses.

To summarize, we find SoCalGas' TY2019 forecast for A&G of \$35.286 million to be reasonable and should be adopted.

34.2. SDG&E

SDG&E's TY2019 forecast for A&G is \$35.977 million⁴¹⁴ which is \$1.846 million less than adjusted, recorded costs for 2016. FOF savings of

⁴¹³ D.14-08-032 at 581 to 582.

⁴¹⁴ Revised from \$35.977 million to \$35.968 million in the Update Testimony (Exhibit 514) at Attachment I.

\$0.935 million are included in the forecast. All costs are O&M costs and all the forecasts utilized a five-year average which is suitable for longstanding divisions. Pursuant to D.16-06-054, costs relating to the Aliso Canyon gas leak incident are not included in the forecast and have been removed from historical information.

As is the case with SoCalGas, certain activities in this section relate to risk mitigation concerning Records Management, which is one of the key risks identified in the RAMP Report. To address this risk, SDG&E plans to hire a third-party records management expert to conduct a gap assessment between current and leading records management policies and practices. The total cost for RAMP-related activities is \$0.791 million.

The four divisions that comprise A&G for SDG&E have the same respective primary functions as was discussed in the SoCalGas section, specifically, in sections 34.1.1 to 34.1.4. The compositions of each division have variances from SoCalGas but many similarities as well and so many of the functions will be similar to those in the SoCalGas section.

34.2.1. A&F Division

The table below shows the various departments that comprise the A&F Division and the forecast costs for each.

A&F Division	TY2019
VP - Controller & CFO	\$120,000
Utility Accounting	\$2,487,000
Accounting Operations	\$4,114,000
Financial Systems and Compliance	\$1,984,000
Financial and Business Planning	\$4,830,000
Total	\$13,535,000

VP - Controller & CFO

Provides accounting and financial oversight.

Utility Accounting

Responsible for the financial statement accounting and reporting and ensuring policies, procedures, and transactional activities are accounted for and presented in compliance with regulations and regulatory directives.

Accounting Operations

Analyzes, records, and maintains the operational and accounting books.

Financial Systems and Compliance

Responsible for managing compliance processes to meet federal and state guidelines, provides financial system support, and manages cost allocation policy and procedures.

Financial and Business Planning

Responsible for developing, measuring, and reporting financial performance targets, provides budget and financial support to business departments, develops and implements the regulatory memorandum and balancing accounts and other cost recovery mechanisms, and develops and implements strategies to optimize all aspects of debt issuances.

34.2.2. Legal Division

The Legal Division provides a wide variety of legal services and performs functions similar to SoCalGas' Legal Division which was discussed in section 34.1.2. The forecast for TY2019 is \$13.407 million⁴¹⁵.

For SDG&E, the Claims Department, including claims payments and recovery costs are included in the Legal Division unlike with SoCalGas where Claims is part of the A&F Division. SDG&E is also requesting for authority to

⁴¹⁵ Revised from \$13.407 million to \$13.413 million in the Update Testimony (Exhibit 514) at Attachment I.

establish the Third-Party Claims Balancing Account (TPCBA) in light of the difficulty in predicting third-party incidents as well as the mismatch between third-party claims to be paid and the amount of insurance available in California largely due to strict liability laws and inverse condemnation.

34.2.3. Regulatory Affairs Division

The table below shows the various departments that comprise the A&F Division and the forecast costs for each.

Regulatory Affairs Division	TY2019
VP of Regulatory Affairs	\$1,146,000
Case Management, Tariffs and Compliance	\$3,557,000 ⁴¹⁶
GRC and Revenue Requirements	\$1,249,000
Total	\$5,963,000

VP of Regulatory Affairs

Serves as liaison between Applicants and federal and state regulatory and agency personnel.

Case Management, Tariffs and Compliance

Supports multiple activities to analyze, respond, and comply with federal and state regulatory agencies.

GRC and Revenue Requirements

Responsible for management of GRC and other major proceedings before the Commission.

⁴¹⁶ Revised from \$3.568 million to \$3.557 million in the Update Testimony (Exhibit 514) at Attachment I. The total for this table do not reflect this revision

34.2.4. External Affairs Division

The table below shows the various departments that comprise the A&F Division and the forecast costs for each.

External Affairs Division	TY2019
VP External Relations	\$727,000
Communications, Regulatory Policy, and Legislative Analysis	\$1,289,000
Community Relations	\$1,056,000
Total	\$3,072,000

VP External Relations

Oversees external communications and community activities.

Communications, Regulatory Policy and Legislative Analysis

Communicates issues of interest to the public, manages external communications, and examines legislative issues in order to recommend actions that serve the needs of customers and support the State’s policy objectives.

Community Relations

The primary liaison with non-profit community-based organizations, faith-based organizations, and local communities.

34.2.5. Positions of Intervenors

ORA, TURN, UCAN and FEA provided comments to this section.

ORA recommends a \$100,000 reduction to the \$200,000 requested by SDG&E to address a RAMP-related activity to mitigate records management risk because SDG&E did not explain how it arrived at its forecast.

TURN recommends the removal from base year 2016 costs of the following: \$85,362 for dues and donations; \$183,000 for charitable contributions; and \$134,000 for clothing and gear (materials and promotions).

UCAN recommends that the Commission reject approval of the TPCBA and instead authorize a memorandum account to track third-party claims that

exceed SDG&E's liability insurance coverage. UCAN adds that SDG&E is already asking for significant costs to mitigate wildfire risks and increased liability insurance costs.

FEA likewise recommends rejection of the TPCBA because it is not warranted, reduces incentives to settle third-party claims, and because SDG&E has not explained the increase in 2016 claims expense over prior years.

34.2.6. Discussion

Nearly all of SDG&E's forecast costs for A&G were not disputed except for \$100,000 that was challenged by ORA which we shall discuss along with other disputed issues. As was the case with SoCalGas' A&G costs, many of the activities that are included in SDG&E's forecasts are activities that have been reviewed in prior GRCs and we also find these to be reasonable and necessary.

We also find the proposed costs to be reasonable and have no objection to the forecast methodology which utilized the five-year historical average which we find appropriate as many of the divisions and activities have been in existence for a long period of time and costs are subject to year-to-year fluctuations. We also find the RAMP-related activities proposed to be reasonable and aimed at addressing mitigation of risks concerning Records Management.

With respect to the recommendations made by ORA and TURN, we find that these are substantially the same as the recommendations made by both parties respectively in the SoCalGas portion and over the same issues except for TURN's additional objection over amounts spent by SDG&E for charitable

contributions. In addition, with respect to dues and donations, SDG&E had already removed \$74,000 out of the \$85,362 recommended by TURN.⁴¹⁷

We make the same findings here as we did in the SoCalGas portion as discussed in section 34.1.6 above and deny regarding ORA's recommendation regarding the \$100,000 reduction to mitigate records management risk, and TURN's recommendations to remove from 2016 costs, costs associated with dues and memberships and clothing and gear. SDG&E also elected to remove the costs associated with dues and memberships for \$11,000 in the Update Testimony (Exhibit 514) at I-1.

For charitable contributions, we find that most of these were spent on sponsorships that provide awareness and education concerning safety, energy efficiency, and customer programs. Thus, we find that these costs should not be excluded. However, we agree with TURN that amounts corresponding to naming rights for a transit system do not support safety, energy efficiency and customer programs and so this amount should be removed.⁴¹⁸

34.2.7. TPCBA

According to SDG&E, the TPCBA addresses the difficulty in predicting the number of claims and amounts and the mismatch between third-party claims to be paid and the amount of insurance available in California.

Generally, we agree with SDG&E that predicting the number of claims and associated costs is difficult especially since the number, type, and circumstances

⁴¹⁷ Exhibit 323 at SKH-5.

⁴¹⁸ The exact costs are deemed confidential but are included in Exhibit 494C which was admitted as a confidential exhibit.

surrounding claims may vary with each claim and from period-to-period. For this reason, we agree that a mechanism to track costs is appropriate.

However, with a two-way balancing account, the Commission will have limited opportunity to review, assess, or determine whether the utility acted negligently or imprudently with respect to a claim. In such cases, ratepayers should not be responsible for any payments arising from such claims. Therefore, we agree with UCAN that a memorandum account is more appropriate and allows SDG&E to seek recovery of any under-collections but also gives the Commission an opportunity to review whether recovery is appropriate.

SDG&E argues that a balancing account will record actual costs and allows the return of any over-collections to ratepayers. However, we find that there is much greater concern with regards to under-collections as actual costs for third-party claims may far exceed what had been forecast. A two-way balancing account also does not fully address payments arising from the utility's negligence or imprudence and as FEA states, reduces incentives to settle third-party claims and manage costs. In addition, pursuant to the RAMP process, this decision is authorizing many of the costs associated with mitigating risks that can lead to third-party claims and as discussed in section 30, is also authorizing increased funding for liability insurance as well as greater flexibility for obtaining additional insurance coverage through the LIPBA.

Therefore, we find it reasonable to authorize the creation of a third-party claims memorandum account (TPCMA) in lieu of the TPCBA. SDG&E can seek recovery of reasonable costs in excess of the authorized amount for third-party claims by through the advice letter process by filing a Tier 2 advice letter to request recovery of such amounts.

To summarize, we find SDG&E's TY2019 forecast for A&G of \$35.953 million to be reasonable and should be adopted. We find that base year 2016 A&G costs should be reduced by the amount corresponding to the naming rights for a transit system. We also find that it is reasonable to authorize the creation of the TPCMA to track third-party claims and allow SDG&E to seek recovery of any under-collections by filing a Tier 2 advice letter.

34.3. Meals and Entertainment

Meals and Entertainment are expenses incurred by employees in the course of doing business. These expenses are associated with meal expenditures often associated with travel, attending meetings out of the office, or overnight meetings away from an employee's home. These also include costs for lunch meals that may be incurred during meetings that extend over the lunch hour.

While both SDG&E and SoCalGas consider meal expenditure expenses as necessary and reasonable business expenses that are recoverable in rates, Applicants are specifically not seeking recovery of these costs in the current GRC only and on a non-precedential basis. According to Applicants, this one time policy decision was made in recognition of the impact of the resulting rates that will be authorized on their customers. Costs for meals and entertainment for TY2019 are estimated at approximately \$0.736 million for SoCalGas and \$0.442 million for SDG&E.

We have no objections to and commend SDG&E and SoCalGas for voluntarily excluding costs for Meals and Entertainment from their proposed revenue requirements in an effort to reduce rates for the benefit of their customers. We treat this policy decision as a one-time decision and consider this as non-precedential for future GRCs. For this GRC cycle, costs for Meals and

Entertainment will be embedded in various non-labor sections of various cost centers.

34.4. IT Business Unit Capital Projects

In addition to the above requests, SoCalGas and SDG&E are requesting funding for IT projects in support of Controller, Regional Affairs, and Legal activities. SoCalGas is requesting \$0.847 million in 2017, \$1.192 million in 2018, and \$1.123 million in 2019 while SDG&E is requesting \$1.369 million.

For SoCalGas three of the projects address technical obsolescence and we find these to be reasonable and necessary because the projects provide necessary upgrades for various areas such as the RO Model and reporting requirements in addition to eliminating the need for additional FTEs to perform functions that are being addressed by the upgrades. However, for the Claims Analytics project, we find that SoCalGas does not provide sufficient testimony how being able to read data from several separate systems will provide enough tangible benefits or why the reporting capabilities within those separate systems are inadequate. Although SoCalGas identified several benefits, the testimony is insufficient to make a determination as to the degree of improvements over current capabilities. Thus, we find it reasonable to deny the funding of \$1.192 million in 2018, and \$1.123 million in 2019 requested for this project.

Meanwhile, SDG&E is requesting \$1.369 million for two projects to replace an outdated legacy application that will automate manual process relating to contributions in aid of construction and a project that will streamline cost recovery efforts and support regulatory filings with FERC.

Based on the above, we find it reasonable to approve the requested funding of SoCalGas and SDG&E for their respective capital projects in 2017 and deny the requested funding by SoCalGas for the capital project in 2018 and 2019.

35. Shared Services and Shared Assets Billing, Capital Reassignment, and Business Segmentation

This section contains our review and analysis of Shared Services and Shared Assets billings, Capital Reassignment, and Business Segmentation.

Shared Services are activities that are performed by SDG&E and SoCalGas departments (that are designated as Shared Services departments) for the benefit of SDG&E or SoCalGas, Sempra Corporate Center, or unregulated Sempra affiliate companies.

Shared Assets pertain to assets that are booked on the financial records of either SDG&E or SoCalGas, but also benefit the other utility, Sempra, or Sempra affiliates.

Capital Reassignment is how SDG&E and SoCalGas reassign certain costs that have not been directly assigned (to O&M or capital) to capital to recognize that the costs are incurred in support of construction efforts.

Segmentation occurs only with SDG&E and is the process of allocating SDG&E's common costs into Gas, Electric, or Electric Generation. Costs allocated to Electric are further allocated between Electric Distribution and Electric Transmission.

35.1. Shared Services Billings

Shared Services costs incurred by one utility on behalf of the other utility or on behalf of Sempra or its affiliates are billed to those companies receiving services. The concept is similar to the allocation to SDG&E and SoCalGas of activities performed by the Corporate Center which we discussed in section 29 of this decision except that the activity is performed by either SDG&E or SoCalGas instead of the Corporate Center. SDG&E and SoCalGas have the same policy for Shared Services Billings and the policy is pursuant to the Affiliate Transactions Rules in accordance with D.97-12-088.

Each Shared Services department is responsible for determining the proper allocation of costs which is then billed to the entity receiving the services. Services are billed at fully loaded costs which mean that indirect charges and overhead costs are added to direct costs of the goods or services. Overhead costs consist of labor and non-labor as well as indirect support costs. For services billed to unregulated entities, a premium cost for direct labor is added to the fully loaded costs.

Shared Services costs are directly allocated to the entity receiving the goods or services whenever possible. If costs cannot be directly allocated, percentage allocation is used and most activities are allocated in this manner. Allocation is applied using the causal/beneficial method as the primary allocation method. If this method cannot be applied, allocation is conducted by applying a multi-factor method which weighs four factors, revenue, gross plant and investments, operating expenses, and FTEs. This allocation method is also similar to the allocation method discussed in the Corporate Center section.

The total allocation forecasted for SDG&E is \$73.010 million and \$37.234 million for SoCalGas.⁴¹⁹ Exhibit 324 contains the various Shared Services allocation subtotals including retained costs, book expense, Corporate Center return charges, and overhead credit for both SDG&E and SoCalGas.⁴²⁰

⁴¹⁹ Revised from \$73.010 million to \$72.986 million for SDG&E and \$37.234 million to \$37.124 million for SoCalGas in the Update Testimony (Exhibit 514), these amounts are embedded in the Summary of Earnings in Attachment A for SoCalGas and Attachment B for SDG&E.

⁴²⁰ Exhibit 324 at JV-13 to 14.

35.2. Shared Assets Billings

Shared assets are recorded on the financial records of the utility that receives the most service or use from the asset and is deemed the owner of the asset. For assets where the service or use is equal, it is recorded in the records of SoCalGas. The recorded owner of the shared assets is responsible for billing the other utility or Sempra and affiliate companies their allocated share.

Assets are allocated based on utilization factors that vary depending on the asset. For example, software is allocated based on the number of users. Allocation percentages are reviewed annually to ensure that affiliates are being billed the appropriate level of costs. Major categories of shared assets include land, structures and improvements, computer hardware and software, common communications, and electronic communications. For each asset category, an annual weighted-average rate base is calculated to determine billable charges which are then apportioned among Applicants, Sempra, and affiliate companies based on allocation percentages.

The total amount of shared assets billed-out to affiliates is forecasted at approximately \$5.386 million for SDG&E and \$54.398 million for SoCalGas.⁴²¹ Exhibit 324 contains a summary of the shared assets billing by SDG&E and SoCalGas which include subtotals for major asset categories.⁴²²

⁴²¹ Revised from \$5.386 million to \$5.417 for SDG&E and \$54.398 to \$54.867 million for SoCalGas in the Update Testimony (Exhibit 514). These Summary of Earnings are embedded in the Summary of Earnings in Attachment A for SoCalGas and Attachment B for SDG&E.

⁴²² Exhibit 324 at JV-18 to 19.

35.3. Capital Reassignment

Capital Reassignment is the process wherein certain operating costs in support of construction activities such as A&G expenses, labor overheads such as pension and benefits, and clearing account costs are re-assigned to capital and become part of rate base.

The projected reassignment for SoCalGas is approximately \$185.523 million⁴²³ and for SDG&E is a combined \$183.853 million⁴²⁴ for the Electric Department, Electric Generation, and Gas Department. Exhibit 324 includes a list of expenses subject to capital reassignment and a table showing the reassignment rate for both SDG&E and SoCalGas.⁴²⁵

35.4. Business Segmentation Allocation

Business Segmentation Allocation is only applicable to SDG&E. For SDG&E, the following are directly assigned to the appropriate department: (a) FERC account series of Clearing Accounts; (b) Customer Accounts; (c) Customer Service and Information; and (d) A&G Accounts related to the Electric Department, Electric Generation, or the Gas Department. However, general expenses that are not directly chargeable to any of the three departments are considered common costs that are allocated among the three. Common costs allocated to the Electric Department are further allocated between Electric Distribution and Electric Transmission. Electric Transmission expenses are not recoverable in Commission jurisdictional rates and are excluded from the GRC.

⁴²³ Revised from \$185.523 million to \$186.209 million in the Update Testimony (Exhibit 514) at A-1.

⁴²⁴ Revised from \$183.853 million to \$183.424 million in the Update Testimony (Exhibit 514) at B-1.

⁴²⁵ *Id.* at JV-27.

Methods used to calculate allocation percentages vary depending on the account to be allocated. Exhibit 324 describes the method used for each particular account⁴²⁶ and also includes a table showing SDG&E's segmentation rates.⁴²⁷

35.5. Electric Transmission Allocation

Costs allocated from SDG&E's Electric Department to Electric Transmission are forecast at approximately \$82.815 million for O&M and \$42.249 million for capital.⁴²⁸ These costs are under the jurisdiction of FERC and are excluded from the GRC. These include warehousing, purchasing, fleet, shops, exempt material, and small tools. SDG&E provides the allocation percentages in Table JV-13 of Exhibit 324.

35.6. Positions of Intervenors

ORA is the only party that provided comments to this section. ORA does not oppose the Shared Services and Shared Assets billing policies and allocation process but presents different totals⁴²⁹ that reflect the summation of ORA's different expense and capital witnesses. ORA does not oppose the Capital Reassignment and Segmentation process applied by Applicants and the allocation of these costs. Finally, ORA also does not oppose SDG&E's allocation of costs to Electric Transmission.

⁴²⁶ Exhibit 324 at JV-23 to 24.

⁴²⁷ *Id.* at Appendix E.

⁴²⁸ Revised from \$82.815 million to \$82.024 million for O&M and \$42.249 million to \$42.239 million for capital in the Update Testimony (Exhibit 514) at B-1.

⁴²⁹ Exhibit 420 at 4 to 5 and 8 to 9.

35.7. Discussion

We reviewed Applicants' and ORA's testimonies regarding the policies and process applied by both SDG&E and SoCalGas to Shared Services and Shared Assets billings and Capital Reassignment, Business Segmentation, and Electric Transmission allocations. SDG&E and SoCalGas apply the same policies, process, and methodologies except for Business Segmentation and Electric Transmission allocation which only apply to SDG&E.

We find that the policies and methods applied to Shared Services and Shared Assets billings are in compliance with the Affiliate Transaction Rules in D.97-12-088. This is the same process that has been applied in Applicants' prior GRCs. With respect to SDG&E's and SoCalGas' total forecasts for Shared Services and Shared Assets billings and the different totals that were calculated by ORA, we find that the resulting totals will be calculated by the RO model and that the forecasts presented are mere approximations based on the different O&M and capital requests, proposals, and recommendations by Applicants and ORA. Thus, we are approving the methods and policies to be applied and the actual values will be calculated by the RO model based on various O&M and capital costs that are authorized throughout this decision.

The Capital Reassignment process complies with the Plant Instructions provided in CFR⁴³⁰ and has been applied in Applicants' prior GRCs. Lastly, SDG&E's Business Segmentation and Electric Transmission allocation approaches apply methods, such as the allocation ratio applied to labor, that have been adopted by FERC and the Commission in prior GRCs. We find that

⁴³⁰ The Plant Instructions are in Part 101 and Part 201.

compliance with Federal Regulations and application of standards authorized by FERC ensures consistency between state and federal regulations which is appropriate in this case. As with Shared Services and Shared Assets billings, what is important with respect to our analysis is the reasonableness and appropriateness of the allocation methods and policies adopted. The actual values will to be calculated by the RO model and will depend in part on the O&M costs and capital projects that will be authorized in the decision.

Based on all of the above, we find the methods and policies applied by SDG&E and SoCalGas with respect to Shared Services and Shared Assets billings and Capital Reassignment are reasonable, supported by the record, and should be adopted. We make the same conclusion with respect to the Business Segmentation and Electric Transmission allocations applied by SDG&E and find that these should be adopted as well. The final and actual values for the above will be calculated by the RO model.

36. Rate Base

Rate base is the net investment of property, plant, equipment, and other assets that Applicants have respectively acquired or constructed to provide utility services to their customers.

This section will examine the components of weighted average rate base⁴³¹ used by SDG&E and SoCalGas to derive their respective TY2019 estimates. There are four major components of rate base which are Fixed Capital, Working Capital, Other Deductions, and Deductions for Reserves. What is included in

⁴³¹ The weighted average rate base is calculated using a 13-month average from December of the prior year to December of the current year less one-half of each December monthly balance then divided by twelve.

these components varies slightly between SDG&E and SoCalGas which we shall examine for each utility.

36.1. SoCalGas

SoCalGas' projected rate base for TY2019 is \$6.997 billion.⁴³² In Exhibit 376, SoCalGas presented testimony of its capital planning process for determining and prioritizing capital funding. The process is based on risk-informed priorities and input from operations. After taking input from functional groups, a high-level assessment of the capital requirements for providing service to customers is made by committee and a prioritization ranking of proposed capital work is developed and then reviewed and finalized. Key priority metrics include safety, cost effectiveness, reliability, security, environmental, and customer experience.⁴³³

36.1.1. Rate Base Components

36.1.1.1. Fixed Capital

Fixed capital is comprised of Plant-In-Service, Allowance for Funds Used During Construction, and Work-In-Progress.

Plant-In-Service

Represents the gross fixed assets used for utility operations with expected life that exceeds one year from the time it is placed in service. Plant-In-Service comprises a very large portion of Fixed Capital.

⁴³² Revised from \$6.997 billion to \$7.023 billion in the Update Testimony (Exhibit 514) at A-1.

⁴³³ Exhibit 376 at PDM-3.

Allowance for Funds Used During Construction (AFUDC)

The term used for debt and equity funds used to finance capital additions. These amounts are applied to CWIP and the regulatory practice is to capitalize these costs to allow the utility to earn a fair return for the funds used.

Work-In-Progress (non-interest bearing)

Represents project costs for plant in construction that is not subject to AFUDC. These are for capital additions that are placed in service within 30 days of construction or purchase such as capital tools.

36.1.1.2. Working Capital

Working cash is comprised of Materials and Supplies (M&S) and Working Cash.

M&S

Costs for purchased materials to be used primarily as current inventory for construction, operation, maintenance, and contract work.

Working Cash

Funds advanced by shareholders and investors to operate the business. The regulatory practice is to capitalize these funds to allow a fair rate of return.

36.1.1.3. Other Deductions

These are deductions applied to the weighted average rate base.

Customer Advances for Construction

Refundable cash advances for construction paid by third parties or customers that requested installation of new business mains and services. The cash advances are subject to refund when new customers are added to these lines.

Deferred Revenue for Income Tax Component of Contribution

Tax gross-up for contributions in aid of construction. The gross-up amount reflects the present value of future tax benefits for the assets.

Repairs Deduction Rate Base Adjustment

Represents the reduction to rate base as directed by D.16-06-054.

36.1.1.4. Deductions for Reserves

These are also reductions applied to the weighted average rate base.

Accumulated Depreciation Reserve

The weighted average book value of the total accumulated depreciation charged against all plant assets on the balance sheet.

Accumulated Deferred Taxes (Plant)

Represents the tax effect of the difference between a normalized depreciation and accelerated depreciation allowed for federal tax purposes. The regulatory practice is to treat this difference as a reduction to rate base.

Accumulated Deferred Taxes (CIAC)

Represents the amount of federal taxes paid on contributions and advances received in aid of construction subsequent to February 10, 1987. Pursuant to D.87-09-026, this amount is a reduction on the Deductions for Reserves which means the amount is ultimately added to rate base.

36.1.2. Positions of Intervenors

TURN is the only party that provided comments to this section and recommends using SoCalGas' actual rate of return for 2017 instead of the authorized rate of return for calculating the weighted average rate of return. TURN calculated the 2017 result to be 62 basis points lower than what SoCalGas calculated and thus recommends that the 2018 and 2019 values be reduced by 62 points from what SoCalGas proposes. TURN also recommends that the M&S

forecast should be escalated from the average M&S balance for 2016 instead of the year ending balance.

36.1.3. Discussion

The components utilized to determine rate base which were discussed in this section have been recognized by the Commission as the major components used to determine and calculate rate base through the RO model in prior GRCs. Very generally, the method seeks to determine the total value of fixed assets used in providing utility services to customers. This value is then adjusted by various additions and deductions. Additions include costs of obtaining funds used to construct fixed assets which are not yet completed, funds advanced by shareholders to operate the business, and funds used to purchase inventory. Deductions include the accumulated depreciation of fixed assets, deferred taxes, and deferred revenues.

We have reviewed these components and find it reasonable to adopt them as components to rate base. Parties do not object to the rate base components presented by SoCalGas. TURN's objection is not on the components themselves but with regards to the calculation of two elements thereof which we discuss below.

In its rebuttal testimony, SoCalGas accepts TURN's proposal regarding the M&S calculation and we agree that the average M&S balance for 2016 should be used as a basis for the M&S calculation in the RO model instead of the year-end balance. This reduces the M&S calculation for TY2019 by approximately

\$835,000,⁴³⁴ the reduction was made in the Update Testimony (Exhibit 514) at H-1.

TURN's argument is that the average actual AFUDC rate for 2017 of 7.36 percent is more accurate than applying SoCalGas' 2017 authorized rate of return of 8.02 percent which was used in the RO model.

While we agree with TURN that actual data is more accurate than forecasts or estimates, we agree with SoCalGas that it is generally not feasible or prudent to continue to update forecasts to reflect actual data during the pendency of the GRC proceeding. The GRC proceeding is comprised of a multitude of forecasts based on an even greater amount of historical data. But because the GRC proceeding extends over a considerable period of time, newer and more recent data becomes available while the proceeding is pending. However, in order to be able to conclude the proceeding, it is reasonable and prudent for the Commission to stop considering updated information at some point in time. Otherwise, the proceeding may be subjected to continuously review and consider constant updates leading to inconsistencies if only certain forecasts or information were to be updated.

The Commission recognizes that there may be instances where it is more appropriate to rely on more recent and more accurate data such as when the difference between actual results is grossly disproportionate to the forecast, if the forecast methodology was found to be flawed, or if new and material information becomes known that warrants the use of more recent data, to name a few examples. However, we find that this instance is not one of such cases and

⁴³⁴ Exhibit 494 at 104.

use of the authorized rate of return for estimating AFUDC as applied to construction work in progress is a practice that has been generally accepted and applied by the Commission in previous GRCs.

Following the above, we therefore find it reasonable to also apply the authorized rates of return for 2018 and 2019 to estimate the AFUDC rates for 2018 and 2019 respectively.

36.2. SDG&E

SDG&E's projected rate base for TY2019 is \$5.44 billion⁴³⁵ for electric and \$1.04 billion⁴³⁶ for gas compared to 4.03 billion for electric and \$657,171 for gas in 2016. SDG&E provides a description of its capital planning process in Exhibit 379. The process is the same process used by SoCalGas which we summarized in section 36.1.

36.2.1. Rate Base Components

36.2.1.1. Fixed Capital

For SDG&E, fixed capital is only comprised of Plant-In-Service which is the gross fixed assets used for utility operations with expected life that exceeds one year from the time it is placed in service. For SDG&E's electric component, this is the electric plant-in-service while for gas, it is the gas plant-in-service. AFUDC is considered as a component of Plant-In-Service and is not presented as a separate component of Fixed Capital unlike with SoCalGas.

⁴³⁵ Revised from \$5.44 billion to \$5.457 billion in the Update Testimony (Exhibit 514) at B-2.

⁴³⁶ Revised from \$1.04 billion to \$1.080 billion in the Update Testimony (Exhibit 514) at B-5.

36.2.1.2. Working Capital

This is comprised of M&S and Working Cash but the gas portion includes a third component which is Fuel in Storage. M&S and Working Cash have the same definitions as described in section 36.1.1.2 under the SoCalGas portion.

Fuel in Storage

Consists of the gas line pack or the gas occupying all pressurized sections of the gas pipeline network. This component is only applicable to the gas section.

36.2.1.3. Other Deductions

For both Electric and Gas, other deductions is comprised of Customer Advances for Construction and the Repairs Deduction Rate Base Adjustment mandated by D.16-06-054 and these have the same definitions as described in section 36.1.1.3 which is the SoCalGas portion. Unlike SoCalGas, SDG&E does not have a separate component for the tax gross-up for contributions in aid of construction.

36.2.1.4. Deductions for Reserves

For both electric and gas, this is comprised of Accumulated Depreciation Reserve, Accumulated Deferred Taxes, and Accumulated Amortization Reserve. The first two have the same definitions as described in section 36.1.1.4 which is the SoCalGas portion. SDG&E's Accumulated Deferred Taxes is only for plant assets and unlike SoCalGas, SDG&E does not have a separate component for deferred taxes for federal taxes paid on contributions and advances received in aid of construction.

Accumulated Amortization Reserve represents the accumulation of the provision and salvage costs less retirement and removal costs for land rights, software, and limited-term investments.⁴³⁷

36.2.2. Positions of Intervenors

TURN raises the same argument concerning the AFUDC rate as it did in the SoCalGas section. TURN's calculation for the 2017 AFUDC rate is 7.38 percent which is 41 basis points lower than SDG&E's which is 7.79 percent. TURN also recommends that SDG&E's AFUDC rates for 2018 and 2019 rates be reduced by 41 basis points. TURN also recommends a lower calculation for M&S inventory based on several calculation adjustments such as not applying escalation to long-term equipment and to equipment that will not be used until 2019.

ORA recommends higher forecasts for both electric and gas customer advances for construction based on a different methodology. ORA also recommends exclusion of line pack gas worth approximately \$285,000 from rate base arguing that the carrying cost for the line pack gas should be addressed in SDG&E's next ERRRA proceeding.

FEA argues that the Ocean Ranch Substation Land and Oceanside Substation Land should be excluded from rate base until both are used and useful. FEA also made recommendations concerning Working Cash and estimated amounts for Plant-In-Service.

⁴³⁷ Exhibit 379 at RCG-12 and 18.

36.2.3. Discussion

M&S Adjustments and AFUDC rate

SDG&E agrees with TURN's M&S calculation adjustments resulting in an M&S inventory of \$97.284 million and we agree that long-term service equipment and equipment that will not be used until 2019 should not be subject to escalation.⁴³⁸ With respect to TURN's argument concerning AFUDC, we reiterate our discussion in section 36.1.3 where we discussed the same issue for SoCalGas. Our conclusion here is the same which is that we find it reasonable to apply the authorized rate of return for AFUDC as applied to construction work in progress for 2017, 2018, and 2019.

Customer Advance for Construction Forecast

Both ORA and SDG&E used forecast methodologies based on the same five-year period of 2012 to 2016. ORA however, applied a linear regression method to account for the fact that balances have been increasing each year. SDG&E's method used a five-year average and argues that a five-year average captures periods in the business cycle where there are expansions, troughs, and recessions.

While we agree with SDG&E that a business cycle does have phases of troughs and recessions, the five-year historical data shows that customer advances for construction have been increasing each year. This suggests that continued expansion is likely to continue within this GRC cycle and SDG&E did not provide specific reasons or arguments why it expects this trend cease.

⁴³⁸ M&S inventory reduction of \$17.610 million made in the Update Testimony (Exhibit 514) at I-1.

Thus, we find that ORA's recommended forecasts of \$48.801 million for electric and \$2.717 million for gas customer advances for construction should be adopted. SDG&E suggests using a customer growth factor to forecast the TY2019 balance but did not elaborate on any specifics regarding this proposal and there is insufficient information in the record of the proceeding to consider this proposal.

Gas Fuel in Storage

ORA recommends that the line pack gas or gas fuel in storage be excluded from rate base and the issue should instead be addressed in the next ERRR filing. Gas Fuel in Storage is a component of Working Cash and represents gas that is in pressurized sections of SDG&E's gas pipeline network. Because this amount of gas inventory is always maintained to ensure that key sections of SDG&E's pipeline network constantly has adequate pressure to maintain smooth operations, we find that it is appropriate to include this amount of gas as part of rate base. This is also consistent with how the Commission has treated Gas Fuel in Storage in SDG&E's prior GRCs.

Land Held for Future Use

SDG&E's response to FEA's arguments is that both the Oceanside Substation Land and the Ocean Ranch Substation Land have been included in construction projects and estimated completion dates for construction of substations are March 2019 and August 2019 respectively. We agree with SDG&E that both lands were transferred to construction within the five-year period the Commission generally applied for which land can be considered as Land Held for Future Use. The Oceanside Substation Land was purchased in 2012 and included in a construction project on August 2017 while the Ocean Ranch Substation Land was purchased in 2013 and transferred to a construction

project in May 2018. Thus, both lands are now part of construction projects from the time they were transferred to such projects and are not anymore considered as Land Held for Future Use.

And while both constructions have been delayed, the current estimated completion dates of March 2019 and August 2019 are still within the periods for which the assets will be placed in service for this GRC cycle. Therefore, we find that both lands are appropriately included in rate base.

Adjustments Recommended by FEA

FEA's recommended adjustments concerning Working Cash are addressed in the section on Working Cash and its concerns concerning the level of capital that will be authorized is addressed in our review and analysis of the various capital proposals by SDG&E throughout the decision.

Undisputed Rate Base Components

With respect to the rate base components that are undisputed, as discussed in the SoCalGas portion in section 36.1.3 of the decision, these rate base components have been recognized by the Commission as the major components used to determine and calculate rate base through the RO model. We have reviewed these components that are either additions or reductions to rate base and find that these have been utilized in prior GRCs and should be adopted as components to rate base.

37. Depreciation

This section addresses depreciation and amortization expense of SoCalGas and SDG&E. The purpose of depreciation and amortization expense is to

provide recovery of the original cost of plant (less estimated net salvage⁴³⁹) over the used and useful life of a property by means of an equitable plan of charges to operating expenses.⁴⁴⁰ Generally, tangible assets such as plant, property, and equipment are depreciated while intangible assets such as software and land rights and rights-of-way are amortized. The cumulative depreciation and amortization costs are respectively reflected in the depreciation and amortization reserves.

37.1. SoCalGas

For TY2019, SoCalGas is requesting a depreciation and amortization expense of \$606.83 million⁴⁴¹ and accumulated reserve of \$8.081 billion. These amounts were calculated pursuant to a proposed request to change the current depreciation parameters for determining average service life (ASL) and net salvage rate of assets. By comparison, the depreciation and amortization expense for TY2016 was \$463 million which was calculated based on the application of depreciation parameters authorized in D.16-06-054. Depreciation parameters refer to the average service life, retirement dispersion, and net salvage rate for a group of assets. The formula SoCalGas used for annual depreciation expense is:

$$\frac{\text{Original Cost} - \text{Accrued Depreciation} - \text{Net Salvage}}{\text{Average remaining life of asset}}$$

The table below shows the proposed depreciation and amortization expense for TY2019 and also 2016 recorded costs. Most of the increase in costs is

⁴³⁹ Net salvage is salvage amount minus cost of removal.

⁴⁴⁰ Exhibit 382 at FN-iii.

⁴⁴¹ Revised from \$606.83 million to \$609.462 million in the Update Testimony (Exhibit 514) at A-1.

from plant growth and not from SoCalGas' proposed changes in depreciation parameters for determining ASL.

Depreciation Expense	TY2019	2016 Recorded
Underground Storage	\$47,306,000	\$26,979,000
Transmission	\$61,961,000	\$45,461,000
Distribution	\$281,812,000	\$232,891,000
General Plant	\$81,367,000	\$60,692,000
<i>Total Depreciation</i>	\$472,446,000	\$366,023,000
Amortization Expense		
Land Rights	\$460,000	\$815,000
Software	\$133,000,000	\$96,561,000
<i>Total Amortization</i>	\$134,384,000	\$97,375,000
Total Depreciation and Amortization	\$606,830,000	\$463,398,000

SoCalGas conducted a depreciation study to determine depreciation rates that will allow for full recovery of costs for assets (minus net salvage) over the life of such assets. SoCalGas states that the procedures and methods used to determine its proposed depreciation rates are consistent with professional and technical depreciation manuals including CPUC Standard Practice U-4.⁴⁴²

The depreciation study includes data collection, analysis, evaluation, and calculation. Historical data was compiled to develop mortality summaries, observed life tables and survivor curves for analysis. These were then analyzed leading to the final selection of lives and net salvage parameters. The last phase of the study involves the calculation of accrual rates, making recommendations, and documenting. SoCalGas describes different methods utilized to determine depreciation life for different types of assets and the method to determine net

⁴⁴² Standard practice U-4 has been prepared to assist Commission staff engineers and others in determining proper annual depreciation expense accruals.

salvage rates in Exhibit 382.⁴⁴³ Finally, the results of the depreciation study as applied to asset groupings by functional class are also presented in Exhibit 382.⁴⁴⁴

37.1.1. Positions of Intervenors

ORA and TURN provided comments to the depreciation section.

ORA does not take issue with SoCalGas' depreciation and amortization parameters.

TURN argues that the Commission should maintain the already existing depreciation parameters due to SoCalGas' inadequate showing in support of their proposals and failure to demonstrate the reasonableness of their proposed depreciation and amortization parameters. TURN also proposes a reduction to SDG&E's decommissioning cost estimate for large-scale electric production facilities from \$19.515 million to \$16.504 million.

37.1.2. Discussion

parameters authorized in D.16-06-054 that increase average service lives of assets and future cost of removal. For purposes of this decision, change in depreciation parameters refers to SoCalGas' proposed new average service lives and net salvage values for the different asset groups or plant categories that are owned by SoCalGas based on the depreciation study that it conducted.

We find that increasing the ASL of assets decreases the annual depreciation expense accrual in the sense that costs are stretched out over a longer period of time. However, this also increases depreciation expense because the longer end-of-life results in less salvage value and higher labor costs incurred

⁴⁴³ Exhibit 382 at FN-6 to 10.

⁴⁴⁴ *Id.* at FN-12 to 24.

which results in increased cost of removal because cost of removal is a component of the asset's depreciable basis. The above changes can be thought of as offsetting but the change in depreciation parameters results in an increase of approximately \$6.5 million for TY2019.⁴⁴⁵

We carefully considered the proposals, testimony, and arguments by SoCalGas and TURN and find that SoCalGas did not adequately demonstrate the reasonableness of its proposed changes to the current depreciation parameters. Generally, SoCalGas explains the method they elected, supplies the data analyzed, and provides the resulting calculations. However, we find that SoCalGas does not provide sufficient input and explanation regarding analysis of its selected methods and why the current depreciation parameters need to be changed. SoCalGas does not provide sufficient testimony that the current depreciation parameters are deficient and will not provide full recovery of the original cost of assets or that its proposed new methods are superior to the current one. There is no comparison between the proposed new parameters and the current one. In effect, SoCalGas proposes to adopt new depreciation parameters but provides no discussion and analysis regarding the current parameters that are in effect. In addition, there appears to be insufficient input regarding analysis of its proposed methods, as TURN pointed out with respect to when and how SoCalGas applied informed judgment of experts and field personnel. And there is also insufficient explanation as to how and why it arrived at the conclusions that it did. SoCalGas argues that it utilized the same

⁴⁴⁵ *Id.* at FN-3.

format as the TY2016 GRC but we find that SoCalGas is proposing substantive changes and not just following an approved format.

Based on the above, we find it reasonable to reject SoCalGas' request to change the current depreciation parameters and subsequently find that \$598.207 million should be authorized for depreciation and amortization expense for TY2019 after deducting the \$6.5 million impact resulting from the proposed changes to the current depreciation parameters. And as stated above, the resulting increase compared to 2016 recorded expenses is from plant growth.

37.2. SDG&E

SDG&E's request for depreciation and amortization expense in TY2019 is \$559.662 million⁴⁴⁶ and an accumulated reserve of \$5.718 billion⁴⁴⁷. Similar to SoCalGas, these amounts were calculated pursuant to a proposed request to change the current depreciation parameters for determining ASL and related salvage rates. By comparison, the depreciation and amortization expense for TY2016 was \$407.147 million based on the application of depreciation parameters authorized in D.16-06-054.

The table below shows the proposed depreciation and amortization expense for TY2019 and also 2016 recorded costs.

⁴⁴⁶ Revised from \$559.662 million to \$562.538 million in the Update Testimony (Exhibit 514) at B-1.

⁴⁴⁷ Revised from \$5.718 billion to \$5.714 billion in the Update Testimony (Exhibit 514).

Depreciation Expense	TY2019	2016 Recorded
Common Tangible Plant	\$54,063,000	\$30,516,000
Electric Tangible Plant	\$369,453,000	\$274,587,000
Gas Tangible Plant	\$50,054,000	\$37,499,000
<i>Total Depreciation</i>	\$474,570,000	\$342,602,000
Amortization Expense		
Land Rights	\$2,303,000	\$2,135,000
Software	\$82,789,000	\$62,410,000
<i>Total Amortization</i>	\$86,092,000	\$64,545,000
Total Depreciation and Amortization	\$559,662,000	\$407,147,000

The depreciation study described in the SoCalGas section was also applied to SDG&E and applies the same process of data collection, analysis, evaluation, and calculation. SDG&E then applies the depreciation study and provides a summary of account details and ASL and future net salvage percentage for asset groupings in Exhibit 388.⁴⁴⁸

SDG&E is also proposing an adjustment to the ASL of Desert Star after reviewing the lease contract for the site.

37.2.1. Positions of Intervenors

TURN provides the same recommendations and analysis as it did in the SoCalGas section for SDG&E's proposed depreciation and amortization expense. TURN also recommends an ASL of 10 years for the Electric Vehicle Supply Equipment Account (E398.20).⁴⁴⁹ This account does not have an authorized ASL.

ORA proposes a service life adjustment to various accounts such as the Wind Energy Project, and Legacy Meters. ORA also proposes different salvage parameters for a number of accounts including Overhead Conductors and

⁴⁴⁸ Exhibit 388 at MCV-11 to 34.

⁴⁴⁹ Exhibit 503 at 11.

Devices, Underground Circuit, Underground Conductors and Devices, Capacitors, Installations on Customer Premises, and Street Lighting and Signal Systems. ORA also opposes SDG&E request to revise the ASL of Desert Star.

37.2.2. Discussion

The issues raised for resolution here are essentially the same as those discussed for SoCalGas in section 37.1 above. And we make the same findings, analysis, and conclusions as we did in the SoCalGas portion as discussed in section 37.1.2. Thus, we likewise find that SDG&E did not adequately demonstrate the reasonableness of its proposed changes to the current depreciation parameters and does not provide sufficient input and explanation regarding analysis of its selected methods and why the current depreciation parameters need to be changed. SDG&E's witness also provided inconsistent testimony regarding the depreciation study by adopting testimony that states that professional judgment was used to make certain adjustments in order to normalize net salvage activity.⁴⁵⁰ SDG&E's rebuttal testimony also emphasized the role of judgment in the depreciation study.⁴⁵¹ However, the same witness emphasized during hearings the lack of judgment underlying SDG&E's recommended depreciation parameters for plant accounts.⁴⁵²

With respect to the ASL for the Electric Vehicle Supply Equipment Account (E398.20), we agree with TURN that the authorized ASL should be 10 years instead of five as recommended by SDG&E. SDG&E relied on an independent study performed by Sargent & Lundy but as TURN pointed out,

⁴⁵⁰ Exhibit 388 at MCV-10.

⁴⁵¹ Exhibit 391 at DAW-15 to 16.

⁴⁵² Transcript (Volume 27 at 2646 to 2647)

although the study recommends a five-year ASL, the study noted a lack of information about the service life of electric vehicle charging stations and states that the life of such facilities can be extended by maintenance.⁴⁵³ The study also identified another study that referenced a 10-year life for these facilities. Lastly, the Commission in D.16-01-045 considered a 20-year life for such facilities when it authorized the pilot program for such investments.

Based on the above, we therefore find it reasonable to reject SDG&E's request to change the current depreciation parameters and subsequently find that approximately \$25.865 million, representing the impact of the proposed changes to the current depreciation parameters⁴⁵⁴ should be deducted from SDG&E's proposed depreciation and amortization expense for TY2019. In addition, SDG&E should also make any necessary adjustments to reflect the authorized 10-year life for Electric Vehicle Supply Equipment Account (E398.20) instead of its proposed five-year life for the account.

Regarding TURN's argument concerning decommissioning of large-scale facilities, SDG&E's forecast is based on a study conducted by Sargent & Lundy utilizing the average scrap metal value forecast from July 2016 to September 2016 whereas TURN proposes utilizing a 12-month average from May 2017 to April 2018.⁴⁵⁵ SDG&E also applies a 20 percent contingency for labor, materials, and indirect expenses whereas TURN recommends using a 15 percent contingency.⁴⁵⁶

⁴⁵³ TURN Opening Brief at 331.

⁴⁵⁴ TURN Opening Brief at 313 to 314 based on SDG&E's calculated difference between total tangible plant from current and requested parameters in Exhibit 389 at 5 and 8.

⁴⁵⁵ Exhibit 494 at 97 to 100.

⁴⁵⁶ Ibid.

We reviewed both positions and find TURN's proposed method to be more reasonable. TURN's recommendation is based on more recent information covering a longer period of time that reflects relatively significant changes in the forecast for scrap metal value. The timeframe relied on by TURN also includes a five-month period prior to the filing of SDG&E's GRC application such that the information was available to SDG&E. We also find SDG&E's use of a 20 percent contingency is not supported by sufficient justification and by comparison find TURN's recommendation of a 15 percent contingency more reasonable. Based on the foregoing, we find it reasonable to reduce SDG&E's forecast for decommissioning costs for its large-scale electric production facilities by \$3.011 million or from \$19.515 million to \$16.504 million.

The above reductions results in a \$510.990 million that should be authorized for depreciation and amortization expense for TY2019 after deducting \$25.865 million representing the impact of the proposed changes to the current depreciation parameters and \$3.011 million for adopting TURN's proposed forecast for decommissioning of large-scale facilities. The resulting increase compared to 2016 recorded expenses is from plant growth.

Regarding ORA's recommendations, we find the proposed adjustments to existing service lives and net salvage rates for certain accounts to not be necessary in light of our decision to adopt TURN's recommendation of not making any changes to the current depreciation rates. In addition, we find that ORA's proposals are not adequately supported by testimony. ORA generally proposes using 10 and 15-year average net salvage rates but as SDG&E provides, common practice is to use short, medium, and long averages of three, five, and ten years respectively.

With regards to SDG&E's proposal to reduce the ASL of Desert Star by 3.17 years, we find the request to be reasonable since it is based on a correction of the lease and decommissioning schedule as stated in the lease contract for Desert Star. The correction is not based on the depreciation study conducted by SDG&E. ORA's recommendation is based on an assumption that SDG&E mismanaged and misread the contract, but we find that there is no evidence of mismanagement simply because there was an error regarding the terms of the lease contract. In addition, ORA does not actually refute or impugn the terms of the lease contract and we find the correction to be prospective and appropriate in this case.

38. Taxes

This section reviews the estimated tax expenses of SDG&E and SoCalGas for TY2019. Estimated tax expenses are calculated based on the proposed O&M and capital costs requested by both utilities in their respective GRCs and authorization of different amounts other than what Applicants had proposed would require a recalculation of their tax expenses for TY2019.

Tax expenses include payroll taxes, ad valorem or property taxes, income taxes, and franchise fees and these will be discussed for both SoCalGas and SDG&E.

The Tax Cuts and Jobs Act (TCJA) enacted on December 22, 2017 made comprehensive changes to federal tax law and the major impacts to Applicants are the following: (a) reduced federal corporate tax from 35 percent to 21 percent beginning in 2018; (b) elimination of bonus depreciation deduction; (c) elimination of the deduction for transportation fringe benefits provided to employees beginning in 2018; and (d) plant-related excess deferred taxes created by the reduction of the corporate income tax rate and the requirement to use the

Average Rate Assumption Method (ARAM) described in the TCJA. These impacts will be discussed in the income tax portion of both utilities.

In addition, the TCJA eliminated the bonus depreciation rules under the Protecting Americans from Tax Hikes Act of 2015 (PATH Act) which extended bonus depreciation through 2019 although the rate for 2019 was reduced to 30 percent.

38.1. SoCalGas

As stated above, SoCalGas incurs three types of taxes: payroll taxes; property taxes; and income taxes. In addition, SoCalGas incurs franchise fees which are included in its tax estimates. The estimated tax expense for TY2019 is \$219.46 million.⁴⁵⁷

38.1.1. Payroll Taxes

Payroll taxes are assessed on both the employer and the employee but our discussion on Payroll Taxes only relates to SoCalGas' payroll tax liability in its capacity as an employer. Individual employees of SoCalGas are responsible for the employee portion.

SoCalGas' estimated Payroll Tax expense for TY2019 is \$48.831 million⁴⁵⁸ compared to \$35.165 million in 2016. The estimate was developed by applying a tax rate on labor costs for both O&M and capital. Payroll tax liability is incurred from the following:

⁴⁵⁷ Revised from \$219.46 million to \$212.66 million in the Update Testimony (Exhibit 514) at A-1.

⁴⁵⁸ Revised from \$48.831 million to \$48.795 million in the Update Testimony (Exhibit 514) at A-1, Line No. 23 (Taxes Other Than on Income is comprised of \$48.795 million for Payroll Tax and \$77.616 million for Ad Valorem Tax).

Federal Insurance Contributions Act (FICA)

FICA taxes, which are also referred to as social security taxes, are composed of two factors: (a) Old-Age, Survivors, and Disability Insurance (OASDI); and (b) hospital insurance (Medicare). The OASDI and Medicare tax rates were based on schedules contained in the 2017 annual report published by the Social Security Administration (2017 Report).

Federal Unemployment Tax Act (FUTA)

According to SoCalGas, the FUTA wage base is not expected to change through 2019 but the current rate of 2.7 percent is expected to decrease to 0.6 percent for 2019.⁴⁵⁹

California State Unemployment Insurance (CASUI)

The CASUI is composed of unemployment insurance and California employment training tax. The unemployment insurance rate is expected to remain at 3.0 percent and SoCalGas' wage base for employment training tax is expected to remain the same through 2019.

38.1.1.1. Discussion

ORA provided comments to SoCalGas' Payroll Tax forecast. ORA agrees with all of SoCalGas' forecasts except for the OASDI wage base limitations for 2018 and 2019. ORA recommends using actual 2018 data and proposes a revision to the 2019 forecast using a five-year trend to derive the 2017 average wage index.

SoCalGas initially utilized data from the 2017 Report which contained the Social Security Administration's (SSA) forecasts for 2018 and 2019. When the

⁴⁵⁹ Exhibit 261 at RGR-5.

SSA published its actual 2018 wage base limit, SoCalGas recalculated their payroll tax rate using the actual wage base limit for 2018. This is reflected in SoCalGas' update testimony. However, the SSA also provided a revised forecast for the wage base limitation for 2019 but SoCalGas did not recalculate its forecast for 2019 and argues that the revised forecast is still subject to changes. SoCalGas adds that it does not update its GRC forecasts and that doing so would lead to inconsistent results as not all forecasts are regularly updated while the GRC is pending.

While we agree with SoCalGas that it is not practical to constantly update data, in this instance, data from the SSA's 2018 wage update is already being relied on to update the 2018 wage base limit forecast contained in the 2017 Report. We therefore find it practical and reasonable to also update the 2019 wage base limit forecast using data from the 2018 publication rather than continuing to rely on data contained in the 2017 Report. This is because data from the 2018 publication is already being used in the application and we find it more inconsistent if the 2018 wage base limit is based on 2018 information but the 2019 wage base limit is based on 2017 and not 2018 information that is readily available and is already being used in the application.

We agree with the methodology SoCalGas utilized to derive its calculations which follows the computational rules and formulas in the SSA's website for determining the OASDI wage base and find that this method is consistent with its prior GRCs. However, based on the above, we find that SoCalGas should recalculate its TY2019 forecast for Payroll Taxes using the SSA's revised 2018 forecast for the wage base limitation for 2019. We find that the new method being proposed by ORA which uses a least squares trend in their regression analysis is unnecessary since the issue being contested revolves

around the use of the SSA's revised forecast for 2019 rather than any deficiencies regarding the calculation methods that were applied.

38.1.2. Property Taxes

Property Taxes are derived from the assessed value of property and a tax rate as applied to that value. Each year, property owned by SoCalGas is re-assessed as to its market value by the California State Board of Equalization (SBE).⁴⁶⁰ SBE makes a report on SoCalGas' total unitary property or property that is determined to be used in operating the business. Unitary property is subject to property taxes. Non-unitary property or property owned but not used in operating the business is not subject to property tax. In addition, Construction Work in Process is capitalized and not directly charged to property tax expense.

The primary indicator for property value is the Historical Cost Less Depreciation (HLCD). A secondary indicator that is utilized is the Capitalized Earnings Ability (CEA) which recognizes the ability of the property to generate income with regards to its value. An example is property purchased to be used for rental purposes. In this case, future income that will be generated by the property can be forecast.

Table SCG-RGR-2 of Exhibit 261 provides a summary of SoCalGas' estimated property taxes for 2019.⁴⁶¹ The total tax expense estimated for TY2019

⁴⁶⁰ Exhibit 261 at RGR-6.

⁴⁶¹ *Id.* at RGR-9.

is \$83.366 million⁴⁶² compared to \$52.473 in 2016. SoCalGas attributes the change to the increase in total plant-in-service.

38.1.2.1. Discussion

In connection with a data response to TURN, SoCalGas identified a formula error in its property tax calculation⁴⁶³ which it has corrected in its update testimony resulting in a decrease of \$3.626 million to SoCalGas' request. Other initial differences between TURN and SoCalGas were due to incorrect data being examined and applying the calculation of property taxes to SoCalGas' fiscal year rather than the calendar year which is what is used for the GRC.

From our review, we find the updated forecast of \$79.740 million⁴⁶⁴ for Property Taxes to be reasonable and supported by the evidence. We find no issues regarding SoCalGas' methodology in arriving at its updated calculation which is based on the list of unitary property as determined by the SBE. TURN also agrees with the updated forecast after initial differences with SoCalGas had been resolved.

38.1.3. Income Taxes

SoCalGas' forecast for Income Taxes in TY2019 is \$48.2 million.⁴⁶⁵ The tax estimate for TY2019 utilizes the current federal tax and state tax rates of 21 percent and 8.84 percent respectively. SoCalGas' methodology for calculating

⁴⁶² Revised from \$83.366 million to \$77.616 million in the Update Testimony (Exhibit 514) at A-1, Line No. 23 (Taxes Other Than on Income is comprised of \$48.795 million for Payroll Tax and \$77.616 million for Ad Valorem Tax).

⁴⁶³ Exhibit 264 at RGR-20.

⁴⁶⁴ Revised from \$79.740 million to \$77.616 million in the Update Testimony (Exhibit 514) at A-1, Line No. 23 (Taxes Other Than on Income is comprised of \$48.795 million for Payroll Tax and \$77.616 million for Ad Valorem Tax).

⁴⁶⁵ Revised from \$48.2 million to \$47.09 million in the Update Testimony (Exhibit 514) at A-1.

its projected income tax expense is explained in Exhibit 261 including Schedule M and other tax deductions.⁴⁶⁶ A summary of SoCalGas' federal and state income taxes are shown in Tables SCG-RGR-3-1 and SCG-RGR-3-2 of Exhibit 261.⁴⁶⁷ For purposes of this GRC, the discussion on Income Taxes will focus on changes brought about by the TCJA and on specific recommendations by parties. Topics that are not impacted by the TCJA and the more mechanical calculations relating to the computation of income tax expenses are not discussed in detail.

38.1.3.1. Changes from TCJA

Reduction on federal corporate tax

The federal corporate tax was reduced from 35 percent to 21 percent beginning in 2018. The TY2019 forecast applies the new tax rate. For 2018, the tax reduction is captured in SoCalGas' Tax Memorandum Account (TMA) which was created at the Commission's direction in D.16-06-054. Discussion of issues relating to the TMA, existing balances, and future treatment are discussed in a separate subsection.

Elimination of bonus depreciation deduction

Bonus depreciation rules under the TCJA supersede rules under PATH. The TCJA eliminated bonus depreciation rules under PATH and as a consequence, bonus depreciation for regulated utilities such as SoCalGas has been eliminated. There is some question concerning a transition rule for property acquired pursuant to a written binding contract on or before September 27, 2017 but placed in service after such date. However, absent any

⁴⁶⁶ Exhibit 261 at RGR-10 to 22. Schedule M contains the reconciliation of book income with taxable income due to adjustments and deductions to book income to arrive at taxable income.

⁴⁶⁷ Exhibit 261 at RGR-23 to 24.

clear guidance from the Internal Revenue Service (IRS), SoCalGas follows the plain language in the TCJA and does not include bonus depreciation that falls under the period described in the transition rule.

Elimination of deduction for transportation fringe benefits

SoCalGas' forecast incorporates this change under the TCJA.

Return of excess deferred taxes using ARAM

The reduction of the corporate tax rate under the TCJA created excess accumulated deferred income taxes (ADIT) that should be returned to ratepayers. ADIT was formerly calculated based on a payment of deferred income taxes at the former rate of 35 percent but due to the reduction in the tax rate to 21 percent, the amount of ADIT needed to pay the deferred tax is also reduced.

There are two types of excess ADIT, excess deferred taxes on plant-based assets that are subject to the IRS normalization rules, also known as protected assets, and excess deferred taxes on plant-based assets that are not subject to the IRS normalization rules otherwise known as unprotected assets.

For protected assets, the IRS requires using ARAM as defined in section 13001(d)(3)(A) of the TCJA if excess ADIT is to be returned to ratepayers.⁴⁶⁸ According to SoCalGas, ARAM is computed on an asset-by-asset basis and the computation is too complex to include in its GRC workpapers because of the large number of plant-related assets owned by SoCalGas. SoCalGas thus uses tax accounting and depreciation software to compute the ARAM amount for

⁴⁶⁸ Exhibit 261 at RGR-21.

each year.⁴⁶⁹ Additionally, SoCalGas states that the TCJA does not discuss the individual components of plant-based deferred assets and there is uncertainty on how to treat removal costs of assets in the ARAM calculation. For its proposed calculation, SoCalGas adjusts the ARAM calculation by removing the costs of removal from book depreciation.

For unprotected assets, the IRS does not prescribe a methodology for returning excess ADIT to ratepayers. SoCalGas proposes to return unprotected excess ADIT using ARAM as well, stating that the timing differences have been afforded normalization treatment in prior rate case decisions.

38.1.3.2. Tax Memorandum Account

As stated above, the TMA was created pursuant to D.16-06-054. The TMA tracks the difference between tax expenses forecasted and tax expenses incurred resulting from changes in tax law, tax accounting changes, policy changes, or procedural changes. Appendix B of Exhibit 261 shows that TMA balance for 2016.

SoCalGas initially proposed that the TMA be closed because it is no longer necessary. During the pendency of the proceeding however, SoCalGas changed its position and finds that the TMA is still necessary. SoCalGas states however, that the Commission reaffirm that the TMA is not intended as a true-up mechanism for incurred versus forecast taxes that are not due to changes in tax law, tax accounting changes, policy changes, or procedural changes.

SoCalGas is also proposing the creation of a TMA sub-account to separately track impacts of the TCJA implementation through 2018.

⁴⁶⁹ *Ibid.*

38.1.3.3. Positions of Intervenors

ORA and TURN provided comments to SoCalGas' Income Tax proposals.

ORA does not disagree with SoCalGas' Income Taxes forecast for TY2019 but recommends that the TMA be continued and further, that the TMA should track any revenue differences between forecast and actual tax expenses. If there are other changes from the TCJA that result in significant balances, ORA recommends that SoCalGas be required to file an annual advice letter to make appropriate adjustments to revenue requirement.

TURN believes that applying ARAM to both protected and unprotected ADIT results in returning more of the excess ADIT in the future rather than at present. TURN recommends that SoCalGas seek a private letter ruling with the IRS regarding unprotected excess ADIT and that the ARAM amounts be tracked as part of the TMA. TURN also recommends that excess unprotected ADIT be returned to ratepayers excluding removal costs over the next six years.

38.1.3.4. Discussion

Changes from TCJA

SoCalGas applied the new corporate income tax rate of 21 percent to its income tax forecast for TY2019 pursuant to the TCJA. We agree with the methods applied by SoCalGas with regards to bonus depreciation and transportation fringe benefits.

Return of excess ADIT

For protected assets, SoCalGas applies ARAM as required by the TCJA. However, SoCalGas adjusts the ARAM calculation by removing the cost of removal from book depreciation. The IRS does not provide sufficient ARAM guidance regarding whether SoCalGas' adjustment concerning removal costs is appropriate, but we find that excluding costs of removal has the effect of

delaying the refund to ratepayers as compared to not applying this adjustment. This is because the ARAM calculation compares accelerated depreciation to book depreciation and when there is reduced book depreciation (due to excluding cost of removal), there is less total ARAM return of excess ADIT. Absent clear guidance from the IRS, we find it more reasonable to disallow this adjustment as we do not believe that this violates the IRS normalization rules concerning return of excess ADIT in the TCJA and so as not to delay the refund to ratepayers. The above approach is also consistent with D.19-05-020 which is the decision concerning SCE's most recent GRC. Applying the above approach decreases SoCalGas' income tax expense for TY2019 by approximately \$2.95 million.

However, we also find it prudent and reasonable to allow SoCalGas to track the revenue requirement difference between including and excluding cost of removal from the ARAM calculation in the event that the IRS issues a ruling or releases further guidance that is inconsistent with our approach. In such case, SoCalGas should seek recovery of any difference in costs by filing a Tier 2 advice letter seeking appropriate adjustment to its revenue requirement.

For unprotected assets that are not subject to the IRS' normalization rules, the Commission has greater discretion on how the excess ADIT is to be returned to ratepayers. SoCalGas proposes to return the excess ADIT using the ARAM method which means that the return will occur slowly over the life of the assets. However, because the IRS does not restrict how these amounts are to be returned, we find it more beneficial to ratepayers if these excess amounts are returned more quickly and doing so does not create an additional burden to ratepayers in the future. We therefore find it reasonable that excess ADIT from unprotected assets be returned beginning in 2019 but amortized over a six-year period as recommended by TURN. A six-year period allows us to review and

authorize any recommended or necessary adjustments resulting from further clarifications or guidelines from the IRS in SoCalGas' next GRC.

Because we are not applying ARAM to unprotected assets, we find TURN's proposal to first seek a private letter ruling from the IRS to not be necessary although SoCalGas may still do so at its own initiative. However, in recognition of the fact that there are still several issues where the guidelines provided by the TCJA remain unclear, and in order to ensure that the process set forth in this decision does not contravene the IRS' normalization rules, we allow SoCalGas to track these costs as part of the TMA in case further guidelines are provided by the IRS that necessitates an adjustment to the revenue requirements. Any significant changes can then be reviewed and resolved in SoCalGas' next GRC.

Tax Memorandum Account

Because of the many uncertainties surrounding the TCJA and the possibility the IRS may release further rules, policies, guidelines, and interpretations relating to the various provisions under the TCJA, and because of the complexity of certain provisions such as ARAM, we find that the TMA should be maintained in this GRC cycle. However, we find that the purpose of the TMA should not be changed at this time. We agree with SoCalGas that the TMA is not meant as a true-up mechanism between actual and forecast tax expenses that are not caused by changes in tax law, tax accounting methods, tax procedures, and tax policy. The TMA should continue to track only differences resulting from“(a) net revenue changes, (b) mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and

(c) elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes”⁴⁷⁰ as provided in D.16-06-054. Thus, we disagree with ORA’s proposal to track all differences between actual and forecasted tax expenses and also find that an annual advice letter filing because of other changes from the TCJA is not necessary at this time. If such changes do occur, the resulting differences will be tracked in the TMA.

38.1.4. Franchise Fees

The TY2019 forecast for Franchise Fees is \$39.091 million.⁴⁷¹ By comparison, recorded costs for 2016 were \$26.698 million. SoCalGas states that the increase is mostly a result of increased base margins as presented in other witness’ testimonies.

Franchise Fees are payments to counties and incorporated cities pursuant to local ordinances granting a franchise to SoCalGas to place property within public rights-of-way. These are usually pipes, appurtenances, and facilities for transmitting and distributing natural gas to customers.

Fees are calculated using a franchise fee ordinance rate applied to either the summarized receipts within each city or county as allocated by gas pipeline mileage in public rights-of-way, or to the percent of gross receipts. The franchise agreement with each taxing authority specifies which of the above calculations was used. The total payments to all taxing authorities are summed up and divided by the total receipts to arrive at a franchise fee factor. A five-year

⁴⁷⁰ D.16-06-054 at 196.

⁴⁷¹ Revised from \$39.091 million to \$39.164 million in the Update Testimony (Exhibit 514) at A-1.

historical average of fee factors was then used to determine the forecasted fee factor for the TY.

38.1.4.1. Discussion

SoCalGas used a five-year average of franchise fee percentages to forecast the franchise fee factor for TY2019. TURN proposes a franchise fee factor based on a two-year average of franchise fee percentages in 2016 and 2017 and states that the franchise fee percentage has been declining since 2013. TURN's proposal would reduce SoCalGas' franchise fee factor from 1.3720 percent to 1.2918 percent.

We reviewed TURN's proposal but find SoCalGas' methodology of using a five-year average of franchise fee percentages to forecast the franchise fee factor for this GRC to be reasonable. This method has also been the method that has been applied in SoCalGas' recent GRCs and we find that TURN does not provide a compelling reason to deviate from this practice. In this case, we also find that a longer period better captures fluctuation from year-to-year. Therefore, we find that SoCalGas' proposed fee factor of 1.3720 percent and projected Franchise Fee expenses for TY2019 of \$39.091 million⁴⁷² should be approved.

38.1.5. Summary

The following is a summary of our disposition regarding the revenue requirement for SoCalGas' tax expenses:

Payroll Taxes

SoCalGas should recalculate its TY2019 forecast for Payroll Taxes using the SSA's revised forecast for the wage base limitation for 2019.

⁴⁷² The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

Property Taxes

The updated forecast of \$79.740 million⁴⁷³ should be approved.

Income Taxes

SoCalGas should make the following adjustments: (a) apply ARAM for return of excess ADIT on protected assets but do not remove costs of removal from book depreciation during the calculation (decreases SoCalGas' revenue requirement by approximately \$2.95 million); (b) amortize excess ADIT on unprotected assets equally over the next six years; (c) continue the TMA with no changes to its purpose, and only changes to the differences that are currently being tracked consistent with this decision.

Franchise Fees

SoCalGas requested amount of \$39.091 million⁴⁷⁴ should be approved.

38.2. SDG&E

Similar to SoCalGas, SDG&E is also subject to payroll taxes, property taxes, income taxes, and franchise fees. SDG&E's estimated tax expense for TY2019 is \$274.7 million.⁴⁷⁵ The tax expenses and franchise fees have the same components and are derived in the same manner as described in the SoCalGas portion under sections 38.1.1 to 38.1.4.

⁴⁷³ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

⁴⁷⁴ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

⁴⁷⁵ Revised from \$274.7 million to \$272.4 million in the Update Testimony (Exhibit 514) at B-1.

38.2.1. Payroll Taxes

SDG&E's estimated Payroll Tax expense for TY2019 is \$18.266 million⁴⁷⁶ compared to \$13.181 million in 2016. SDG&E states that the increase in Payroll Taxes reflects increases in staffing levels compared to 2016. OASDI and Medicare tax rates were based on schedules contained in the 2017 Report. The FUTA and CASUI rates are the same as those expected for SoCalGas which is 0.6 percent and 3.0 percent respectively.

ORA makes the same proposals and recommendations concerning the OASDI wage base limitations for 2018 and 2019. The issues raised are the same as those discussed in section 38.1.1 with respect to SoCalGas' forecast for Payroll Taxes. We make the same findings and conclusions here with respect to SDG&E's forecast and find that SDG&E should recalculate its TY2019 forecast for Payroll Taxes using the SSA's revised forecast for the wage base limitation for 2019.

38.2.2. Property Taxes

Table SDG&E-RGR-2-1 in Exhibit 265 provides a summary of SDG&E's estimated property taxes for TY2019.⁴⁷⁷ The total tax expense estimated for TY2019 is \$106.163 million⁴⁷⁸ compared to \$70.454 million in 2016. SDG&E

⁴⁷⁶ Revised from \$18.438 million to \$18.266 million in the Update Testimony (Exhibit 514) at B-1, Line No. 24 (Taxes Other Than on Income is comprised of \$18.266 million for Payroll Tax and \$104.696 million for Ad Valorem Tax).

⁴⁷⁷ Exhibit 265 at RGR-9 to RGR-11.

⁴⁷⁸ Revised from \$106.163 million to \$104.696 million in the Update Testimony (Exhibit 514) at B-1, Line No. 24 (Taxes Other Than on Income is comprised of 18.266 million for Payroll Tax and \$104.696 million for Ad Valorem Tax).

attributes the increase in property taxes due to the increase in total plant-in-service.

The formula error applied to the calculation of property tax discussed in the SoCalGas portion also applies to SDG&E and similarly, SDG&E supplied a corrected calculation in its update testimony resulting in a decrease of \$2.602 million, which we accept.

TURN does not dispute the asset base to which property tax will be applied but proposes an adjustment to the property tax rate that will be applied to 1.556 percent as compared to SDG&E's proposed rate of 1.619 percent.

38.2.2.1. Discussion

SDG&E utilized a five-year average from 2012 to 2016 to forecast the average historical rate of increase in local tax rates. The result is then applied as an escalation factor to the 2016 rate in order to forecast the TY2019 rate. TURN proposes using a four-year average from 2014 to 2017. TURN states that the level of increase from year-to-year is generally constant except for 2013 where the increase was unusually high.

Generally, a longer period is used in order to normalize fluctuations that may occur from year to year. In appropriate instances however, a shorter period may be relied on if it is more indicative of what is likely to occur, when there is a change in conditions or a shift in trend from certain years, or in other analogous cases. In this case, TURN concludes that 2013 is an anomalous year and that the rate of increase for said year is unusually high. However, we find that TURN does not provide sufficient analysis to support its claim such as a comparison of the different tax rates from year-to-year or an analysis as to why it considers the rate for 2013 to be unusually high or why the result falls outside normal fluctuations that may occur from year-to-year. For its part, we find that SDG&E

presented a reasonable methodology for its forecast and do not find sufficient basis to conclude that the rate of increase in 2013 was an anomaly that falls outside ordinary fluctuations that may occur from year-to-year. This method is also the method that has been applied in SDG&E's recent GRCs and we find that no compelling reason was presented to support a change in methodology.

Based on the above, we find the proposed property tax rate of 1.619 percent to be reasonable and find that SDG&E's updated forecast for TY2019 Property Taxes of \$103.561⁴⁷⁹ should be adopted.

38.2.3. Income Taxes

SDG&E applies the same methods and principles and makes the same recommendations as SoCalGas with respect to the determination, calculation, and forecast for Income Taxes as discussed in section 38.1.3 in the SoCalGas portion. SDG&E's estimated income tax expense for TY2019 is \$80.8 million.⁴⁸⁰

ORA and TURN make the same recommendations as they did for SoCalGas. In addition, FEA opposes using ARAM to return excess ADIT for unprotected assets because using ARAM is unnecessarily complex. Instead, FEA proposes using a straight-line amortization period of ten years or less. FEA also supports the continuation of the TMA to ensure that all the effects of the TCJA are captured and taken into account.

We make the same findings and conclusions with regards to SDG&E's Income Taxes as we did in the SoCalGas section. Discussion of income tax issues

⁴⁷⁹ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

⁴⁸⁰ Revised from \$80.8 million to \$80.1 million in the Update Testimony (Exhibit 514) at B-1.

are under section 38.1.3.4. FEA recommendations support these findings⁴⁸¹ and conclusions which are summarized in section 38.2.5.

38.2.4. Franchise Fees

SDG&E's TY2019 forecast for Franchise Fees is \$69.271 million⁴⁸² compared to \$50.934 million in 2016. SDG&E attributes the increase in Franchise Fees to increased base margins as presented in other witness testimonies.

SDG&E's forecast was derived using the same methodology as discussed in the SoCalGas section under section 38.1.4 and which we found to be reasonable. We make the same findings and conclusion here and thus find that SDG&E's Franchise Fee forecast of \$69.271 million⁴⁸³ for TY2019 is reasonable and should be approved.

38.2.5. Summary

The following is a summary of our disposition regarding the revenue requirement for SDG&E's tax expenses:

Payroll Taxes

SDG&E should recalculate its TY2019 forecast for Payroll Taxes using the SSA's revised forecast for the wage base limitation for 2019.

Property Taxes

The updated forecast of \$103.561 million⁴⁸⁴ should be approved.

⁴⁸¹ FEA recommends a straight-line amortization of ten years or less and the decision is adopting a six-year amortization period for return of excess ADIT on unprotected assets.

⁴⁸² Revised from \$69.271 million to \$69.351 million in the Update Testimony (Exhibit 514) at B-1.

⁴⁸³ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

⁴⁸⁴ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

Income Taxes

SDG&E should make the following adjustments: (a) apply ARAM for return of excess ADIT on protected assets but do not remove costs of removal from book depreciation during the calculation (decreases SDG&E's revenue requirement by approximately \$3.68 million); (b) amortize excess ADIT on unprotected assets equally over the next six years; (c) continue the TMA with no changes to its purpose, and only changes to the differences that are currently being tracked consistent with this decision.

Franchise Fees

SDG&E requested amount of \$69.271 million⁴⁸⁵ should be approved.

38.3. 2018 TCJA Revenue Requirement Adjustment and Other Issues

SoCalGas and SDG&E provided estimated changes to their respective 2018 revenue requirements resulting from the implementation of the TCJA in Exhibit 514 (Update Testimony). SoCalGas estimates a decrease of \$63.605 million while SDG&E estimates a decrease of \$75.057 million.

2018 is a PTY to Applicants' TY2016 GRCs and so the impact of the TCJA to the 2018 revenue requirement is outside the scope of these TY2019 GRCs. As such, we direct SoCalGas and SDG&E to file separate Tier 2 advice letters within 45 days from the effective date of this decision, to implement adjustments to their respective revenue requirements for 2018 in order to reflect the 2018 tax savings from the TCJA in rates. It is possible that some calculation adjustments applied in this decision may also be applied to the 2018 adjustment

⁴⁸⁵ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

during the advice letter process. For example, SoCalGas and SDG&E should assume the Commission will require cost of removal not be removed from book depreciation when calculating ARAM for 2018.

TMA sub-account

SoCalGas and SDG&E proposes the creation of a TMA sub-account to their respective TMAs to separately track differences between 2018 tax benefits that the Commission may authorize and actual 2018 tax benefits from the TCJA. Applicants state that the full impact of the TCJA will not be known until following the filing of their 2018 tax return.

However, the TMA sub-account presupposes that an estimated or interim tax refund for 2018 will be authorized in this decision or separately but concurrent with this decision. This is not the case however as the estimated 2018 revenue requirement decreases for 2018 due to the TCJA are to be determined in the advice letter filing that Applicants are directed to file. We therefore find it reasonable to deny the creation of the TMA sub-accounts without prejudice to the same requests being made again at the proper forum. We also note that the TMA is not supposed to function as a true-up mechanism for forecasted taxes versus incurred taxes and that the TMA only tracks differences arising from changes in tax law, tax accounting changes, policy changes, or procedural changes. As a result, since the TMA is not a true-up mechanism, it is unclear what impact, if any, the Applicants' actual tax returns could have on the 2018 TCJA savings applied to the adopted PTY2018 Results of Operations model.

SDG&E proposal re TCJA impact on TY2019 Revenue Requirement

In Exhibit 253, SDG&E states that it was exploring options not to reduce the overall revenue requirement with estimated tax savings from the TCJA which SDG&E estimated to be around \$58 million. Instead, SDG&E was

considering submitting supplemental testimony for securing use of a quick strike firefighting helicopter and adjustments relating to general excess and wildfire liability insurance premiums.

During the pendency of the proceeding, SDG&E has not submitted additional testimony providing detail or support to the above proposal and it is unclear whether SDG&E is still pursuing this option. In any case, we find that the request should be denied because it is not supported by evidence and because SB 1028 (2018) requires that utility rates be adjusted to reflect the tax savings. Therefore, we find that the impacts of 2019 tax savings from the TCJA should be incorporated into the TY2019 revenue requirement.

39. Working Cash

Working Cash is the funding supplied by investors to meet day-to-day operational requirements and to cover the time expenditures are made for services until the time revenues are collected for those services. Working Cash allowance is governed by Standard Practice (SP) U-16 and is comprised of balance sheet items and income statement items. The balance sheet items generally account for the operational cash needs while the income statement items quantify the timing between when revenues are collected and when expenses are paid and this timing difference is referred to as lead-lag. The sum of the operational cash requirements and the lead-lag requirements results in the working cash allowance that is needed. Working cash from sources other than investors are then deducted to arrive at the net working cash requirement and is the amount requested in the GRC.

39.1. SoCalGas

SoCalGas' net working cash requirement for TY2019 is estimated at \$169.1 million. The table below provides a general summary of working cash

requirements. A more detailed breakdown of working cash requirements is presented in Table KC4 of Exhibit 173.⁴⁸⁶

Depreciation Expense	TY2019
Operational Cash Requirement	\$243,000,000
Lead-Lag Working Cash Requirement	\$162,600,000
Total Working Cash Requirement	\$405,600,000
Less Working Cash Provided by Non-Investors	\$236,500,000
Net Working Cash Requirement	\$169,100,000

The operational cash requirement represents cash supplied by investors, and establishes the working cash requirement. General categories of these accounts include the cash balance, other receivables, prepayments, and deferred debits. The balance sheet accounts were determined by calculating the monthly weighted-average accounts balances for 2016 and then escalating to 2019 dollars. The 2016 account balances that were included are those necessary to operate efficiently and those accounts that do not bear interest or other carrying costs recovered elsewhere from customers. The monthly ending balances for these accounts were summed except for December which used one-half of the December 2015 and one-half of the December 2016 balances. The total was then divided by 12 to arrive at the monthly average balance.

For the income statement accounts, the working cash requirements were determined by performing a lead-lag study which has two major components: revenue lag and expense lag. Revenue Lag was calculated as the average number of days between the midpoint of all customers' monthly service periods and receipt of payment by SoCalGas. The lead-lag study uses a single value for lag days because customers pay for all services with a single monthly bill.

⁴⁸⁶ Exhibit 173 at KCC-8.

General categories of revenue lag include meter reading lag, billing lag, collection lag, and bank lag.

On the other hand, the Expense Lag is the number of days between the time SoCalGas incurs expenses and the time it pays its suppliers. SoCalGas pays for each expense separately and so each expense category has a separate value of lead-lag days. General categories of expense lag include purchased commodities, payroll and benefit expense, employee benefits, lease payments, various kinds of taxes, insurance premium amortizations, etc.

SoCalGas provides how the lead-lag days in the study were derived and calculated in Exhibit 173⁴⁸⁷ and a summary of the lead-lag study is provided in Table KC3 of the same exhibit.⁴⁸⁸ A table showing expense lag days and recorded expenses for various accounts are also provided in Table KC2.⁴⁸⁹

39.1.1. Positions of Intervenors

ORA and TURN provided comments to SoCalGas' working cash proposals. The comments can be divided into comments on the operational cash requirement and comments regarding SoCalGas' lead-lag proposals.

Operational Cash Requirement

ORA states that SoCalGas' methodology is susceptible to incorrect weighting of expenses and proposes that SoCalGas be required to link individual expense lags to TY expense forecasts in its next GRC rather than using recorded data from the base year. ORA also recommends the exclusion of cash balances,

⁴⁸⁷ Exhibit 173 at KCC-4.

⁴⁸⁸ *Id.* at KCC-7.

⁴⁸⁹ *Id.* at KCC-6.

and GHG asset and liability balances from the determination of working cash. Finally, ORA recommends that customer deposits be treated like long-term debt.

TURN recommends that customer deposits be treated as working capital not provided by investors that should be deducted from the total working capital cash requirement.

Lead-Lag Proposals

ORA recommends a five-year average to determine the revenue lag for TY2019 and a higher expense lag for employee benefits, pension, goods and services, and federal and state taxes.

TURN recommends adjustments to determine revenue lag and a higher expense lag for goods and services and federal and state taxes. TURN also recommends that depreciation and deferred income taxes be removed from working cash as these transactions do not involve actual cash.

39.1.2. Discussion

Operational Cash Requirement Issues

We reviewed ORA's recommendation of directing SoCalGas to link individual expense lags to corresponding individual test year forecasts and find that there was insufficient evidence to show that this method is superior to SoCalGas' method of using just one expense lag which is the weighted average expense lag for 2016. While ORA's method will likely result in some expense lags being longer, some expense lags will end up being shorter potentially offsetting the longer expense lags. In addition, there is some question on whether the current RO model can support an individual computation as according to SoCalGas, the RO model is designed to calculate the revenue requirement for the entire company and not just for working cash. Because there is insufficient information and supporting evidence regarding ORA's assertion,

we find that there is no basis to require SoCalGas to change its method of calculation in the next GRC. This determination however is without prejudice to ORA raising the same argument in SoCalGas' next GRC and offering more evidence to support its assertions.

For cash balances, SoCalGas argues that SP U-16 allows minimum bank deposits and reasonable amounts of working funds to be included in determining the cash requirement. The full text of the provision in SP U-16 reads as follows:

In determining the cash requirement, the only amounts which should be considered are the required minimum bank deposits that must be maintained and reasonable amounts of working funds. The determination of the amount of money required to pay expenses in advance of receipt of revenues is made by the lag study. If funds were to be allowed in the cash requirement, over and above the minimum bank deposits for payment of certain operating expenses, it would have the effect of providing for payments of the same cost twice, once as determined in the lag study and once again in determining the operational requirement. It must be remembered that the cash requirement is not a measure of funds that the utility maintains for all purposes, such as for construction or for payment of dividends and interest. It is the amount that must be maintained for day-to-day operations. When the ratepayer pays his bill, he has compensated the investor for the interest on construction funds and a return on the investor's capital; therefore construction cash, interest and dividends are not included in the cash requirement.⁴⁹⁰

The above provision from SP U-16 also provides that allowing funds over and above the minimum deposit for payment of operating expenses would have the effect of providing for payments of the same cost twice, once as determined

⁴⁹⁰ SP U-16 Chapter 3, I-4 to I-5.

in the lag study and once again in determining the operational requirement. Based on the above, we find that a strict interpretation of SP U-16 should be applied in order to avoid double-counting of funds and that only required minimum bank deposits should be included in the cash requirement. This means that \$4.5 million cash balance that SoCalGas maintains should be excluded from the cash requirement. This approach is consistent with the Commission's determination in D.12-11-051.⁴⁹¹

Regarding GHG asset and liability balances associated with Cap-and-Trade activities, ORA states that these should be excluded from Working Cash as they will receive balancing account treatment from the NERBA which removes all risks associated with such balances. However, SoCalGas explains that these amounts are not included in the NERBA as GHG compliance instruments and emissions expenses are only recorded in the NERBA when they are used to offset actual emissions. The amounts being included in working cash are those that are not used but prudently held for future use as these compliance instruments can be purchased in advance. Working Cash also only excludes amounts that earn interest such as funds recorded in a balancing account. We find it reasonable to compensate investors for fronting money to purchase such instruments which may not all be used at a given point in time. However, we find that it is more appropriate to apply some form of interest to GHG asset and liability balances similar to interest being applied to NERBA account balances rather than to include the GHG asset and liability balances to working cash and ergo part of ratebase. This is because the return on investment for funds used for

⁴⁹¹ D.12-11-051 at 634 to 635.

essentially the same purpose which is to purchase compliance instruments, should not differ drastically depending on whether the compliance instruments were used to offset actual omissions or are held for future use. Thus, we find it more reasonable to apply the short-term debt interest rate to GHG asset and liability balances similar to what is mandated for fuel and commodity inventories.

Regarding increased transparency related to compliance instrument purchases, we note that SoCalGas is already required to file an annual compliance report providing transactional details of GHG activities and conducts periodic discussions with ORA and the Commission's Energy Division regarding compliance instrument activities.⁴⁹² ORA does not make specific recommendations at this time but the Commission is open to review proposals that ORA may make in future proceedings wherein it is appropriate to do so.

Regarding customer deposits, SP U-16 excludes from working cash interest bearing accounts such as customer deposits. TURN argues that that the interest on customer deposits is very small and that SP U-16 is outdated while ORA proposes that customer deposits be treated as long-term debt as was the case in D.14-08-032. However, the ratemaking treatment for customer deposits provided in SP U-16 remains unchanged as of this time and we find it more reasonable to simply apply this rule. Therefore, we find that properly excluded interest-bearing customer deposits from working cash.

TURN proposes to exclude depreciation and deferred income taxes from working cash. While TURN presents good reasons to support its arguments,

⁴⁹² Exhibit 175 at KCC-8 to 9.

TURN does not dispute that depreciation and deferred income taxes are allowed to be included in working cash under the principles set forth in SP U-16. We find that this GRC is not the proper venue to challenge the general applicability of this principle in SP U-16 as this principle is applicable to all utilities and TURN does not cite specific reasons why this principle should not apply to SoCalGas specifically. Based on the above, we find it reasonable to deny TURN's request to exclude depreciation and deferred income taxes from working cash.

Lead-Lag Proposals

For Revenue lag, ORA proposes using a five-year average while TURN proposes using a six-year average. SoCalGas uses 2016 recorded data based on accounts receivables as permitted by SP U-16. We find that ORA's proposed method only results in a small decrease in lag days or 43.32 days versus 44.35 days for SoCalGas. We find it more consistent in this case to utilize SoCalGas' method as SoCalGas applies 2016 recorded data to all of its working cash calculations. However, we will not hesitate to approve a different method whenever it is appropriate to do so. We also disagree with TURN's proposal for similar reasons and also because we find it more consistent not to consider 2017 recorded data in this instance and because there was no sound argument why the 2017 recorded data should be considered.

For Employee Benefits lag, SoCalGas uses a weighted average of lag days for various benefit programs and proposes a lag of 15.84 days. ORA proposes 34.46 lag days based on adjustments of lag days for workers' compensation payments and pension payments. For workers' compensation payments, ORA proposes 18.8 days versus 9 days originally for SoCalGas to which SoCalGas does not object. For pension payments, ORA proposes 59.75 lag days using the due dates for quarterly contributions in the event of a prior year shortfall. On the

other hand, SoCalGas uses 43.08 lag days based on 2016 recorded data. However, in 2016, SoCalGas did not make pension payments in the first two quarters whereas it plans to make quarterly pension payments in 2019. Thus, we find that 2016 recorded data may not reflect conditions in TY2019 and also find ORA's proposed method and calculation of lag days for pension payments to be more reasonable. Based on the above, we find that ORA's proposed lag days of 34.46 for Employee Benefits should be adopted.

SoCalGas agrees with ORA's proposal of raising Goods and Services lag by 2.3 days based on the incorporation of check clearing lag and TURN's argument to increase lag by 0.26 days based on the exclusion of rents from the analysis of other goods and services. This increases the lag days for Goods and Services from 34.00 to 36.56 days.

For federal income taxes (FIT) and California corporate franchise taxes (CCFT), both ORA and TURN recommend lag days based on the date for when quarterly tax payments are due. However, SoCalGas explains that because it is difficult to project the exact amount of taxes that are due, it adopts a conservative approach and more likely than not, ends up paying more than what is due which results in refunds.⁴⁹³ The refunds end up being reflected as lead days in the working cash calculation. SoCalGas uses 2016 actual data to project TY2019 results and has shown that it receives relatively frequent refunds and that it is able to replicate the 2016 results in 2019. Thus, we find SoCalGas' estimate to be reasonable.

⁴⁹³ Exhibit 175 at KCC-15 to 16.

39.1.3. Summary

To summarize, SoCalGas' working cash proposals should be adopted except for the following: (a) exclusion of \$4.5 million in cash balances; (b) the short-term debt interest rate should apply to GHG asset and liability balances; (c) change employee benefit lag days from 15.84 days to 34.46 days; and (d) change goods and services lag days from 34.0 days to 36.56 days.

39.2. SDG&E

SDG&E's net working cash requirement for TY2019 is estimated at \$171.0 million. The table below provides a general summary of working cash requirements. A more detailed breakdown of the separate working cash requirements for electric distribution, gas services, and electric generation are shown in Tables SDG&E-SPD-5, SDG&E-SPD-6, and SDG&E-SPD-7 of Exhibit 176.⁴⁹⁴

Depreciation Expense	TY2019
Operational Cash Requirement	\$97,000,000
Lead-Lag Working Cash Requirement	\$130,000,000
Total Working Cash Requirement	\$227,000,000
Less Working Cash Provided by Non-Investors	\$56,000,000
Net Working Cash Requirement	\$171,000,000

SDG&E utilizes the same principles and methods as SoCalGas did in determining its operational cash requirements and performed a similar lead-lag study to determine revenue and expense lags. These methods are described in the SoCalGas portion under section 39.1. Summaries for the lead-lag study for electric distribution, gas services, and electric generation are provided in

⁴⁹⁴ Exhibit 176 at SPD-9 to 11.

Tables SDG&E-SPD-2, SDG&E-SPD-3, and SDG&E-SPD-4 of Exhibit 176.⁴⁹⁵ A table showing expense lag days and recorded expenses for various accounts are also provided in Table SDG&E-SDP-1.⁴⁹⁶ SDG&E agrees with a proposed modification from TURN that purchased power should be assigned to electric generation and not electric distribution.

39.2.1. Positions of Intervenor

ORA and TURN raise similar comments and makes the same recommendations regarding several working cash components and lead-lag items as the two parties did for SoCalGas as stated in section 39.1.1. Specifically, ORA raises the same issues concerning SDG&E's methodology, recommends exclusion of cash balances and prepayments for GHG compliance instruments from working cash, recommends that customer deposits be treated as long-term debt, recommends a five-year average to determine revenue lag, and recommends higher expense lags for FIT and CCFT, goods and services, and employee benefit expense. TURN once again recommends a higher expense lag for goods and services and recommends that depreciation and deferred income taxes be removed from working cash.

In addition, TURN recommends changes to GHG credit applications and argues that deferred lease incentives should not be averaged and escalated like other working cash components.

FEA adds that prepayments for GHG compliance instruments should be excluded from working cash because GHG credits are already addressed in a

⁴⁹⁵ *Id.* at SPD-6 to 8.

⁴⁹⁶ *Id.* at SPD-5.

balancing account. This issue was already addressed in the SoCalGas portion wherein it was discussed that only GHG compliance instruments not recorded in the NERBA were included by SDG&E in its working cash proposal. FEA also states that customer deposits should be included as a reduction to ratebase but this issue was already raised by ORA and TURN and addressed in the SoCalGas portion.

39.2.2. Discussion

39.2.2.1. Recurring issues from SoCalGas portion

We make the same findings and conclusions over similar issues and recommendations made by ORA and TURN on the following:

Methodology

We find that there is no basis to require SDG&E to change its method of calculation in the next GRC without prejudice to ORA raising the same argument in SoCalGas' next GRC and offering more evidence to support its assertions.

Cash Balance

A strict interpretation of SP U-16 should be applied in order to avoid double-counting of funds. Only required minimum bank deposits should be included in the cash requirement and SDG&E's cash balance of \$4.452 million should be excluded from the cash requirement consistent with D.12-11-051.

Net prepayments for GHG compliance instruments

We find it more reasonable to apply the short-term debt interest rate to net prepayments for GHG compliance instruments similar to what is mandated for fuel and commodity inventories.

Customer Deposits

SP U-16 excludes from working cash interest bearing accounts such as customer deposits and we find that SDG&E properly excluded interest bearing customer deposits from working cash.

Revenue Lag

ORA's proposed method only results in a small decrease in lag days or 40.79 days versus 42.81 days for SDG&E and find it more consistent in this case to utilize SDG&E's as it applies 2016 recorded data to all of its working cash calculations.

Depreciation and Deferred Taxes

Depreciation and deferred income taxes are allowed to be included in working cash under the principles set forth in SP U-16 and this GRC is not the proper venue to challenge the general applicability of this principle as this is applicable to all utilities and TURN does not cite specific reasons why this principle should not apply to SDG&E specifically.

FIT and CCFT

SDG&E uses 2016 actual data to project TY2019 results and has shown that it receives relatively frequent refunds and that it is able to replicate the 2016 results in 2019. We thus find SDG&E's estimate to be reasonable.

Goods & Services Lag

SDG&E agrees with ORA's argument of raising lag by 0.9 days based on the incorporation of check clearing lag and TURN's proposal to increase lag by 1.56 days to incorporate a longer delay for credit card purchases. This increases the lag days for Goods and Services from 33.1 to 34.66 days.

Employee Benefits

ORA proposes 28.76 lag days compared to SDG&E's proposal of 4.50 lag days. ORA's proposal is due to increases in worker's compensation payments, PBOP payments, and pension payments. SDG&E does not oppose ORA's proposal of 18.6 lag days for worker's compensation compared to SDG&E's 9-day estimate and ORA's proposal of 38.35 lag days for PBOP after an adjustment to a true-up payment was correctly applied. For pension payments, we agree with ORA's proposal of using the due dates for quarterly contributions in the event of a prior year shortfall. SDG&E did not make any pension payments in 2016 and we find that the 2016 recorded data may not reflect conditions in TY2019. We thus find ORA's proposed method and calculation of lag days for pension payments to be more reasonable. Based on the above, we find that ORA's proposed lag days of 28.76 lag days for Employee Benefits should be adopted.

39.2.2.2. Unique issues for SDG&E

Errata Adjustments

SDG&E made errata adjustments to its working cash forecast after removing prepaid commercial interest payment, prepaid property taxes, and prepaid survey and investigation costs for the Manzanita Wind Project, and updating its worker's compensation reserves as shown in Exhibit 178.⁴⁹⁷ The errata adjustments also include lag day adjustments from ORA and TURN that it does not oppose and were discussed above.

⁴⁹⁷ Exhibit 178 at SPD-18.

Deferred Lease Incentives

Regarding TURN's argument that deferred lease incentives follow a known and measurable schedule and should not be averaged and escalated like other components of working cash. We agree with TURN that deferred lease incentives follow a known and measurable schedule but note that further lease incentives may occur over the years in this GRC and therefore find SDG&E's method to be reasonable.

GHG Credit Revenue Lag

TURN explains that twice a year, SDG&E returns to customers an amount equal to the revenues that SDG&E receives for auctioning its GHG allowances through the California Climate Credit. However, when calculating revenue lag, SDG&E excludes the GHG allowance auction revenues. We agree with TURN and find that SDG&E did not present compelling reason for this exclusion. Ultimately, SDG&E recovers cash proceeds from GHG allowance auctions and should include these proceeds in its revenue lag calculation.

39.2.3. Summary

To summarize, SDG&E's working cash proposals should be adopted except for the following: (a) exclusion of \$4.452 million in cash balances; (b) apply short-term debt interest rate GHG compliance instruments; (c) change goods and services lag days from 33.1 days to 34.66 days; (d) change employee benefit lag days from 4.50 days to 28.76 days; (e) apply errata adjustments; and (f) include GHG allowance auctions in revenue lag calculation.

40. Customer Forecasts

This section discusses the customer forecasts of SoCalGas and SDG&E. The total number of customers is determined by adding the number of active meters and the forecast for new meters in TY2019. Each meter is assumed to

represent one customer and so the total number of meters represents the total number of customers. In this section, meters and customers are used interchangeably. Only the number of customers is considered in the GRC and not gas volumes. For both SDG&E and SoCalGas, the currently adopted throughput forecast in D.14-06-007 (the last Triennial Cost Allocation Proceeding) is used as the forecast for their respective gas sales.⁴⁹⁸ For SDG&E's electric energy sales, the forecast will be provided in Phase 2 of the TY2019 GRC application. For this section, only ORA and TURN provided comments to Applicants' proposals and so we shall only refer to these two parties in discussing the positions, recommendations, and objections by intervenors.

40.1. SoCalGas

The total number of active customers in 2016 is 5.7 million. SoCalGas forecasts that the number of customers will increase to 5.82 million by 2019. Specifically, a three-year increase of 119,376 customers is expected from 2016 to 2019. This represents a compound annual growth rate of 0.69 percent.⁴⁹⁹ The customer forecast is primarily used to determine the financial needs for customer services and new meter installations which are discussed in the Customer Services Field and Gas Distribution sections respectively.

The forecast methodology consists of different forecasts for different customer types. For residential customers, the forecast is based on new housing starts with the underlying forecast for housing starts taken from the IHS Global

⁴⁹⁸ Exhibit 326 at RMP-1 and Exhibit 328 at RMP-1.

⁴⁹⁹ Exhibit 326 at RMP-1.

Insight (Global Insight) February 2017 regional forecast.⁵⁰⁰ Commercial and Industrial customers were forecast based on commercial and industrial employment respectively. Table RMP-3 of Exhibit 326 shows the annual forecast from 2017 to 2019 for the three groups of residential customers, commercial customers, and industrial customers.

40.1.1. Positions of Intervenors

ORA does not object to SoCalGas' forecast because its own forecast contains minimal differences with that of SoCalGas'. TURN does not object to the forecast by SoCalGas.

40.1.2. Discussion

We reviewed the forecast and do not have objections to the methodology utilized by SoCalGas and using information from Global Insight's regional forecast. Global Insight's forecasts have been utilized or served as the basis for utility forecasts in prior and other GRCs. The resulting customer forecast also tracks well and has minimal differences with historical data since 2012. We note that slightly higher percentage increases are projected for 2018 and 2019 but the difference from annual changes in prior years is around a quarter of 1 percent and is therefore minimal and within acceptable deviations. Thus, based on our review, we find that the forecast of 5.82 million gas customers for 2019 should be adopted.

40.2. SDG&E Gas Customers

SDG&E's average annual gas customers are forecast to increase by 16,957 or from 875,462 customers in 2016 to 892,419 in 2019. This represents an annual

⁵⁰⁰ Exhibit 326 at RMP-2.

compound growth of 0.6 percent. Like with SoCalGas, the forecast number of customers is used to determine the financial needs of customer services and new meter installation which are discussed in the Customer Services Field and Gas Distribution sections respectively. The forecast methodology is also the same as what was utilized for the SoCalGas forecast which utilized different forecasts for different customer types which are residential and non-residential customers. Table RMP-2 of Exhibit 328 shows the annual forecast from 2017 to 2019 for the three groups of residential customers, commercial customers, and industrial customers.

40.2.1. Positions of Intervenors

ORA does not object to SDG&E's forecast because its forecast contains minimal differences with that of SDG&E. TURN on the other hand recommends a reduction of 0.34 percent or 2,933 to the 2018 forecast and 0.59 percent or 5,058 to the 2019. This results in a total reduction of 7,991 customers. TURN recommends using the housing start forecast from Moody's Regional Economic Service (Moody's) rather than Global Insight citing to an over-forecast of gas connections in the prior GRC cycle by over 28,600 connections. TURN states that the cause of the over-forecast was primarily due to overly optimistic housing start forecasts from Global Insight.⁵⁰¹

40.2.2. Discussion

In its rebuttal testimony, SDG&E explains that the housing start data from Moody's was purchased by its electric forecasting unit and that the information

⁵⁰¹ Exhibit 490 at 57.

cannot be shared with affiliate companies including SoCalGas.⁵⁰² SDG&E then explains that its gas customer forecast is performed by the gas demand forecasting unit which is part of SoCalGas' corporate structure. This gas demand forecasting unit performs the gas customer forecasts for both SoCalGas and SDG&E as a shared service. Based on the contractual restrictions that accompanied the Moody's housing start data purchase, we have no reason to not to believe that SoCalGas cannot use the Moody's data. Therefore, we agree that the gas demand forecasting unit which is part of SoCalGas cannot utilize the Moody's data to prepare its gas customer forecast for SDG&E.

Additionally, the fact that Global Insight's forecast of housing starts was inaccurate during the prior GRC period does not suggest that Global Insight is in the habit of over-forecasting. It was not shown through evidence that Global Insight's forecasts are frequently incorrect by large margins for other periods or that their methodology is intrinsically flawed. Forecasting is not an exact science and there will be times that a forecast will be incorrect. For 2017, SDG&E has shown that their forecast of 880,249 meters using the methodology based on Global Insight's data was quite close to 2017 recorded active meters of 880,394.

Based on the above, we find that it is unnecessary to redo the gas customer forecast using Moody's data which will have to be purchased by SoCalGas or the gas demand forecasting unit. We therefore find that the gas customer forecast of 892,419 for TY2019 should be accepted. It should be noted that we are not in any way suggesting or making a finding that Global Insight's data is more accurate than Moody's or vice versa. Additionally, we find that future forecasts should

⁵⁰² Exhibit 330 at RMP-5.

take into account activities by the CPUC and California Energy Commission that may reduce gas use in new construction as applicable.

40.3. SDG&E Electric Customers

The average annual electric customers are forecast to increase by 38,216 or from 1,430,175 in 2016 to 1,468,391 in 2019. The forecast number of electric customers is used to determine the financial needs of customer services and new meter installations in TY2019 and affects the following sections: Customer Services Field; Customer Service Office Operations; Electric Distribution Capital; and Miscellaneous Revenues.

The forecast methodology is based on economic and demographic data, seasonal patterns, and other inputs affecting customer growth. SDG&E utilized information from Global Insight's Regional Economic Service on statistical models and February 2017 information from Moody's. Different forecasts were applied to different customer types. For residential customer growth, the number of housing starts, and seasonal factors were used as a basis. Commercial and industrial customers were forecast based on growth in employment while agricultural customers and street lighting were forecast using trend analyses. Table KES-1 in Exhibit 331 shows the annual forecast for each customer type from 2016 to 2019.

40.3.1. Positions of Intervenors

Once again, ORA does not object to SDG&E's forecast because its forecast contains minimal differences with that of SDG&E. TURN recommends using only data from Moody's instead of a blend of both Moody's and Global Insight which results in a reduction to SDG&E's forecast of 2,204 customers in 2018 and 3,808 in 2019. Similar to its argument in SDG&E's gas customer forecast, TURN

cites to Global Insight's overly optimistic housing start forecast which led to an over-forecast of electric customers by over 23,000 during 2014 to 2016.

40.3.2. Discussion

For the electric customer forecast, data from Moody's is available to use unlike the case for SDG&E's gas customer forecast. We reviewed both SDG&E's and TURN's position and find it more reasonable to use both the Global Insight data as well as Moody's since both are available for use. We find that it was not clearly established, from the evidence presented by both parties, whether the data from Moody's or Global Insight is superior or inferior from the other. Thus, we find it more reasonable to rely on both sets of data although we considered TURN's argument that the two use different methods to arrive at their forecast and that Global Insight's forecast in 2014 to 2016 was higher than the actual result. However, as we stated in Section 40.2.2, forecasts may not be accurate at times and it was not established that Global Insight's forecasts are frequently incorrect, or their methodology intrinsically flawed so as to make any forecast by Global Insight completely unreliable.

In addition, we find that a difference of 6,012 customers out of the total forecast of 1,468,391 customers will have minimal impact on the financial needs of customer service and miscellaneous revenues which rely on the forecast number of customers for their own TY2019 forecast. It does have more impact with respect to the financial needs for new meter installations if the forecast of 38,216 new meters is reduced by 6,012. However, given the uncertainty of forecasts and what we have discussed in the previous paragraph, we find it unnecessary to direct SDG&E to redo its electric customer forecast. It is not established that Moody's forecast is certain to be accurate or that Global Insight's forecast is certain to be inaccurate. We find it more prudent to rely on both

forecasts to minimize the impact of a vastly incorrect forecast from either company. Therefore, we find that relying on both sets of data is reasonable and that the forecast of 1,468,391 electric customers for TY2019 should be adopted.

41. Cost Escalation

Cost escalation refers to the changes in the utilities' expenses from 2016 to 2019. This section examines the cost escalation factors used by SDG&E and SoCalGas to reflect the effect of external inflation to labor and non-labor and capital costs. Cost escalators were used to adjust for inflation the costs from 2016 nominal dollars⁵⁰³ into TY2019 nominal dollars using various escalation indexes.

Labor O&M escalation utilized a weighted average of three IHS/Markit Global Insight wage and salary cost indexes. The weightings are based on Applicants' recorded 2016 labor earnings for three corresponding employee categories: represented employees; non-represented non-supervisory employees; and non-represented supervisory employees which include managers, directors, and executives.

Non-Labor O&M escalation combined various weighted Global Insight utility costs indexes to develop a single index which is based on Applicants' recorded base year expenses.

Capital Cost escalation utilized construction cost indexes forecasted by Global Insight which are based on recorded Handy-Whitman cost series for the Pacific Region.⁵⁰⁴

⁵⁰³ Nominal dollars use the dollar value at the time the goods were produced, or service rendered. Nominal dollars are not adjusted for inflation as opposed to real dollars.

⁵⁰⁴ Exhibit 334 at SRW-4 and Exhibit 336 at SRW-4.

41.1. Discussion

We reviewed the testimony presented by Applicants as well as the escalation adjustments in the update testimony and find that the testimony reasonably support Applicants' escalation cost indices. The indices are based on Global Insight cost indexes which have been relied on in past GRCs. Applicants also utilized recorded labor earnings and base year expenses in developing the indices. Parties did not dispute the cost escalation factors and updated cost escalations by Applicants. Based on the foregoing, we find Applicants' cost escalations to be reasonable and should be adopted. The cost escalation factors applicable to the PTYs shall be discussed in the PYT Revenue Requirement section of the decision.

42. Miscellaneous Revenues

Miscellaneous Revenues are fees and revenues for specific products and services collected from non-rate sources. Common examples of such fees and revenues are collection fees, rents, and charges. Miscellaneous revenues are incorporated into rates as a reduction to base margin revenue requirements for utility service and therefore lower rates charged to customers.

SDG&E and SoCalGas utilized a similar forecast methodology by performing an item-by-item analysis of miscellaneous revenue accounts and review of historical recorded results. Forecasts were then developed using methodologies that reflect the cost drivers for each item. For example, when charges are from a per-customer basis, customer growth was used to adjust historical results. For revenue from rents, the forecast is based on lease agreements which are escalated as applicable.

42.1. SoCalGas

SoCalGas' forecast for TY2019 is \$83.114 million⁵⁰⁵ which is \$21.186 million lower than recorded costs for 2016 of \$104.300 million. The table below lists the various accounts for miscellaneous revenues and shows the forecast for TY2019.⁵⁰⁶ Most of the forecast methodologies incorporate historical data so the table includes recorded amounts for 2016 and the net change between the 2019 forecast and 2016 values. The amounts have been adjusted to reflect the impact of the TCJA. The list also includes two new fees that were not charged in 2016, the Advanced Meter-Opt-Out Fee, and Gas Land Services Right-of-Way. SoCalGas is also requesting to eliminate the Service Establishment Charge beginning in TY2019.

⁵⁰⁵ \$4,000 was added to the Returned Checks total per Exhibit 340 at AMS-2 and Appendix B.

⁵⁰⁶ Total amounts may not reflect the exact sum of the individual accounts shown in the table due to rounding.

Miscellaneous Revenue Component	2016 Recorded	TY2019	Net Change
A. Customer Service Revenues Total	\$30,806,000	\$10,921,000	(19,885,000)
Service Establishment Charge	\$21,574,000	\$0	(21,574,000)
AMI Opt-Out Fee	\$0	\$1,054,000	\$1,054,000
Reconnection Charge	\$1,797,000	\$1,513,000	(284,000)
Residential Parts Program	\$2,539,000	\$2,889,000	\$350,000
Commercial Parts Program	\$3,535,000	\$4,037,000	\$502,000
Connect Appliance Program	\$87,000	\$110,000	\$23,000
Natural Gas Vehicle Maintenance	\$131,000	\$99,000	(32,000)
Pipeline Services	\$78,000	\$60,000	(18,000)
Late Payment Charges	\$510,000	\$521,000	\$11,000
Other Customer Service Revenues	\$555,000	\$639,000	\$84,000
B. Rent from Gas Property Total	\$471,000	\$489,000	\$18,000
C. Other Gas Revenues Total	\$73,024,000	\$71,704,000	(1,320,000)
Shared assets ⁵⁰⁷	\$54,576,000	\$54,398,000	(178,000)
Crude Oil Sales	\$3,467,000	\$3,846,000	\$379,000
Goleta Storage Emission Credit Lease	\$1,023,000	\$1,023,000	\$0
Returned Check Charge ⁵⁰⁸	\$557,000	\$500,000	(57,000)
Contributions-in-Aid-of Construction Tax Component	\$3,871,000	\$6,297,000	\$2,426,000
Training Activity	\$415,000	\$542,000	\$127,000
Line Item Billing	\$5,142,000	\$804,000	(4,338,000)
Federal energy Retrofit Program	\$366,000	\$112,000	(254,000)
Miscellaneous Other Gas Revenues	\$306,000	\$875,000	\$569,000
Microwave Bandwidth Revenue	\$31,000	\$30,000	(1,000)
Ownership Charges	\$3,270,000	\$3,276,000	\$6,000
Miscellaneous Revenues Total	\$104,300,000	\$83,114,000	(21,186,000)

⁵⁰⁷ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

⁵⁰⁸ Adjusted for the \$4,000 error identified in Exhibit 340 at AMS-2.

42.1.1. Miscellaneous Revenue Accounts

In this section, we provide a brief description of the various Miscellaneous Revenue accounts. Because there are numerous accounts, the reasonableness of SoCalGas' forecast for these different accounts is discussed together instead of individually. It should be noted that the forecast for each account, as well as the applicable forecast methodology utilized by SoCalGas, was reviewed individually.

42.1.1.1. Customer Service Revenues

The accounts under this sub-section are service related fees.

Service Establishment Charge

Fee charged to establish service for a customer. The fee is \$25 and \$10 for CARE customers. SoCalGas is proposing to eliminate this charge beginning in TY2019.

AMI Opt-Out Fee

The fee applicable for enrolling in the Residential Advanced Meter Opt-Out Program. The fee is applicable for three years from the time of enrollment. SoCalGas is requesting to continue the current fee structure.

Reconnection Charge

The \$16 fee charged for re-establishment of service after the account is closed for non-payment.

Residential Parts Program

Provides limited parts replacement for residential-type gas appliances.

Commercial Parts Program

Provides parts replacement for food industry-type appliances located in commercial establishments including hospitals, schools, and churches.

Connect Appliance Program

Provides connection of new and used portable appliances such as gas ranges, dryers, barbecues and gas logs upon request of customers.

Natural Gas Vehicle Maintenance

Revenues are received for providing maintenance services at customer-owned natural gas vehicle facilities. Service may include oil and filter changes, minor mechanical adjustments, replacement of hoses, and for other maintenance-related items.

Pipeline Services

Revenues for installation and/or maintenance of gas facilities. These services are primarily for commercial customers, school districts, cities, and counties.

Late Payment Charges

Fees charged to residential and non-residential customers for late payment of bills. The monthly charge is one-twelfth of SoCalGas' authorized rate of return on rate base multiplied by the unpaid balance.

Other Customer Service Revenues

Revenues derived from miscellaneous programs including timed appointments, seismic and non-seismic restore, and other services.

42.1.1.2. Rents from Gas Property

These revenues are derived from rentals of gas property by outside parties. The TY2019 forecast is based on rents received for existing lease agreements with adjustment for escalation provisions in the agreement.

42.1.1.3. Other Gas Revenues

The accounts under this section are for revenues from provision of various services, crude oil sales, returned check charges, training programs, line item billing, and includes shared asset charges to affiliates.

Shared Assets

Reflects the use of SoCalGas' assets by SDG&E, Sempra and Sempra affiliate companies. Assets shared are primarily hardware, software, and communications equipment.

Crude Oil Sales

Revenues from sale of crude oil produced at SoCalGas' underground storage fields: Aliso Canyon; Honor Rancho; and Plaza del Rey.

Goleta Storage Emission Credit Lease

Revenues from the lease of emission-offset credits⁵⁰⁹ at the Goleta storage facility.

Returned Check Charges

Revenues from customers whose checks are returned due to insufficient funds. SoCalGas charges a \$7.50 fee for each returned check.

Income Tax Component of Contributions-in-Aid-of-Construction

Represents the gross-up for income tax payments for contributions-in-aid-of-construction. Taxes are paid upon receipt of the contributions and the gross-up reflect future tax benefits to be received through tax depreciation over the tax life of the constructed property.

⁵⁰⁹ Emission offset credits fund and support projects and activities that reduce emissions.

Training Activity

Revenues for training activities provided to third-party companies, utilities, and contractors such as welding training and welding re-certification.

Line Item Billing

Revenues for billing services offered to third parties providing energy-related and home safety-related products and services to customers. Third parties provide products and services and the charge is included in a customer's gas bill as a single line item.

Federal Energy Retrofit Program

Revenues represent net positive amounts from monies collected from government agencies for project management under infrastructure improvement contracts less actual costs incurred to perform the work.

Miscellaneous Other Gas Revenues

Revenues from all other items not reflected in other sections, such as Regional Clean Air Incentives Market credits, mapping services, land and right-of-way revenues, etc.

Microwave Bandwidth Revenue

Revenue from leasing excess capacity on the SoCalGas' microwave network to third parties.

Ownership Charges

Charges to recover the cost of operating and maintaining customer-financed facilities that are not fully utilized.⁵¹⁰

⁵¹⁰ The charges are assessed in accordance with SoCalGas' Commission approved Tariff Rules 20 and 21.

42.1.2. Positions of Intervenors

ORA and CFC are the only parties that provided comments to SoCalGas' requests concerning this section.

ORA found minimal differences between the 2017, 2018, and TY2019 amounts for the various accounts under miscellaneous revenues and do not oppose SoCalGas' forecast.

CFC proposes an increase of \$205,000 to revenues from Reconnection Charges. CFC argues that revenue from Reconnection Charges have been increasing since 2012 with only 2014 showing lower revenues than 2012 and the three-year historical average utilized by SoCalGas for its forecast does not correctly reflect these increasing revenues. In addition, the higher rates proposed in the GRC are predicted to lead to more disconnections due to economic reasons and subsequently, result in more reconnections.

42.1.3. Discussion

We reviewed the testimony presented and the arguments and positions raised by parties in briefs and will first discuss the only disputed account which is the Reconnection Charge.

We find that the three-year historical average utilized by SoCalGas for its forecast is adequate. Recorded revenue from Reconnection Charges increased from 2015 to 2016 but then decreased from 2016 to 2017. The same is true for the prior GRC period where there was one period where revenues decreased. Thus, a historical average better reflects both increases and decreases especially since the difference in revenues are relatively small. CFC also states that there is a time-lag for the rate increase in 2016 to be reflected in the form of increased number of disconnections subsequent to and as a result of the rate increase. However, we find that this assumption, although it may ultimately be more

correct than incorrect, is not adequately supported by the evidence that was presented.

In addition, while rates and number of customers are both forecast to go up, leading to an assumption that the number of disconnections and subsequent reconnections will increase as well, we find that this is offset by the different policy considerations and practices in place that seek to limit the number of disconnections. Although it does so voluntarily, SoCalGas states that it continues the end-of-year holiday moratorium and extreme weather policy concerning disconnections. Based on the above, we find that SoCalGas' forecast revenues for Reconnection Charges is reasonable and should be adopted.

With respect to the other accounts, we agree with ORA that almost all the estimates show relatively minimal differences from recorded amounts. The large decrease forecast for Line Item Billing revenues was adequately explained by the end of vendor contract in early 2019. We also have no objections to the forecast methodologies that were used with many of the forecasts appropriately using historical revenues as a basis. We also find the proposed amounts for all of these accounts to be reasonable and they should be adopted except for the Service Establishment Charge, which we discuss below.

SoCalGas requests to eliminate the Service Establishment Charge and instead allocate the cost across all customers by class. While this certainly benefits customers who would otherwise have to pay the charge, another effect is to remove the revenues that would have been deducted from SoCalGas' base margin resulting in higher rates. Using 2016 recorded data as the TY2019 forecast, \$21.574 million would have been deducted from base margin revenue requirements. SoCalGas states that eliminating the fee would encourage customers to sign-up for service and is detrimental to low income customers. We

disagree. The fee is a one-time fee of \$25 per customer or \$10 for CARE customers and does not seem to be a big incentive or disincentive to sign-up for service. New customers will only have to pay the fee once and existing customers need not pay for it again unless they move, and no evidence or argument was presented that customers often move so as to incur repeated charges. Also, low income customers are supported by having to pay a lesser amount to \$10. We are also not persuaded that this one-time fee will lead to nonpayment, customer complaints, and increased use of customer service and other resources.

Additionally, customers that have already paid the fee will not have to be concerned with or burdened by costs being allocated to them due to the actions of others. We also find it more reasonable to assess these charges to customers that were responsible for establishment costs as opposed to having every other customer in the class be responsible for the establishment costs. Lastly, we find that SoCalGas has failed to demonstrate that eliminating the charge is more beneficial to customers as a whole than using the revenues that would be earned to reduce base margin revenue requirements and rates charged to customers.

Therefore, in view of the above, we find that SoCalGas' request to eliminate the Service Establishment Charge for this GRC period should be denied without prejudice to making the same request in its next GRC with better evidence as to the benefits thereof. Because no forecast was made for TY2019, we adopt the 2016 recorded amount as the TY2019 estimate. The amount of \$21.574 million should be added to the Miscellaneous Revenues total resulting in an amount of \$104.688 million that should be adopted.

42.2. SDG&E

SDG&E's forecast for TY2019 is \$17.496 million which is \$376,000 higher than recorded costs for 2016. The two tables below list the various accounts for electric and gas miscellaneous revenues and show the forecast for TY2019. As was the case with SoCalGas, most of the forecast methodologies incorporate historical data so the table includes recorded amounts for 2016 and the net change between the 2019 forecast and 2016 values. The amounts have also been adjusted to reflect the impact of the Tax Cuts and Jobs Act.

Electric Department	2016 Recorded	TY2019	Net Change
A. Miscellaneous Service Revenues Total	\$4,169,000	\$4,398,000	\$229,000
Service Establishment Charge	\$2,402,000	\$2,523,000	\$121,000
Collection Charges	\$99,000	\$86,000	(13,000)
Late Payment Charges	\$598,000	\$592,000	(6,000)
Returned Check Service Charge	\$269,000	\$209,000	(60,000)
Direct Access Fees	\$59,000	\$69,000	\$10,000
Cogeneration Reimbursement	\$172,000	\$207,000	\$35,000
Smart Meter Opt-Out Revenues	\$92,000	\$27,000	(65,000)
Other Service Revenues	\$478,000	\$685,000	\$207,000
B. Rent from Electric Property Total	\$4,676,000	\$3,626,000	(1,050,000)
Rent from Electric Property	\$1,012,000	\$1,091,000	\$79,000
Special Facility Charges	\$2,867,000	\$2,031,000	(836,000)
Customer Advances for Construction	\$756,000	\$455,000	(301,000)
Other Miscellaneous Revenue	\$41,000	\$49,000	\$8,000
C. Other Electric Revenues Total	\$5,108,000	\$6,629,000	\$1,521,000
Revenue Cycle Service	(248,000)	(251,000)	(3,000)
Pole Attachment Fees	\$1,910,000	\$2,900,000	\$990,000
Shared Assets ⁵¹¹	\$4,043,000	\$3,335,000	(708,000)
Federal Turnkey Program	(615,000)	\$340,000	\$955,000
Emergency Services Revenues	\$0	\$50,000	\$50,000
Parts Replacement Program	\$18,000	\$255,000	\$237,000
Electric Department Total	\$13,953,000	\$14,653,000	\$700,000

⁵¹¹ The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

Gas Department	2016 Recorded	TY2019	Net Change
Service Establishment Charges	\$1,183,000	\$1,176,000	(7,000)
Collection Charges	\$43,000	\$37,000	(\$6,000)
Late Payment Charges	\$46,000	\$50,000	\$4,000
Smart Meter Opt-Out Revenues	\$50,000	\$15,000	(35,000)
Rent from Gas Property	\$23,000	\$26,000	\$3,000
Customer Advances for Construction	\$117,000	\$65,000	(52,000)
Federal Turnkey Program	\$124,000	\$132,000	\$8,000
Shared Assets ⁵¹²	\$1,581,000	\$1,342,000	(239,000)
Gas Department Total	\$3,167,000	\$2,843,000	(324,000)

42.2.1. Miscellaneous Revenue Accounts (Electric Department)

Most of the accounts listed in the table above are the same as the accounts described in Section 42.1.1 and so we only provide brief descriptions of the Miscellaneous Revenue accounts that we have not already described in the SoCalGas section. Again, the reasonableness of the forecasts is discussed together instead of individually although each account and accompanying forecast methodology was reviewed individually.

42.2.1.1. Miscellaneous Service Revenues

Service Establishment Charge

See section 42.1.1.1. The fee is \$5.85

Collection Charges

Revenues from charges levied on customers to pay for the costs of delivering field collection notices.

Late Payment Charges

See section 42.1.1.1.

⁵¹² The Final Decision Summary of Earnings reflects an updated calculation as a result of various changes adopted in this decision.

Returned Check Service Charge

See section 42.1.1.3

Direct Access Fees

Charges billed to energy service providers for late payments and billing requests and metering charges billed to direct access customers.

Cogeneration Reimbursement

Billing of cogenerators and small power producers for utility O&M expenses for work performed at customer facilities.

Smart Meter Opt-Out Revenues

Revenues from residential customers that opt-out from having a wireless smart meter installed.

Other Service Revenues

Revenues from other customer service items, primarily: temporary service work, meter testing, billing and other service charges.

42.2.1.2. Rent from Electric Property

Rent from Electric Property

Revenues received for use of operating sites, properties, and licenses by third parties.

Special Facility Charges

Revenues from installation, use, and maintenance of facilities.

Customer Advances for Construction

Reductions from advances if the customer does not become eligible for refunds.

Other Miscellaneous Revenues

Revenues not contained in any of the three categories above such as electric right-of-way fees.

42.2.1.3. Other Electric Revenues

These are revenues received from other sources.

Revenue Cycle Service

Credits to direct access customers who elect to have billing and metering services from another party.

Pole Attachment Fees

Revenues from Communication Infrastructure Providers for use of SDG&E's distribution poles.

Shared Assets

See section 42.1.1.3 except these are for use of SDG&E assets.

Federal Turnkey Program

Revenues reflect the difference between amounts collected from government agencies less actual costs for project management contracts to implement cost-effective energy conservation measures.

Emergency Services Revenues

Revenues from emergency restoration for customer-owned facilities located at Camp Pendleton.

Parts Replacement Program

Revenues from a pilot program for field parts replacement.

42.2.2. Miscellaneous Revenue Accounts (Gas Department)

All the accounts in the Gas Department have corresponding accounts in the Electric Department and these are defined in the Electric Department sections that they appear in.

42.2.3. Positions of Intervenors

ORA is the only party that had objections to SDG&E's Gas and Electric forecasts under Miscellaneous Revenues. ORA states that SDG&E did not

sufficiently support its forecast for electric Shared Assets other than stating that the forecast is based on the RO model. Thus, ORA recommends using a five-year average which results in a \$5.818 million forecast compared to SDG&E's forecast of \$4.043 million. ORA also cites to the testimony of witness Vanderhye indicating an estimate of \$5.938 million.

ORA also objects to SDG&E not including revenues for the income tax component of contributions in aid of construction similar to SoCalGas and states that this component is required to be accounted for pursuant to D.87-09-026.

42.2.4. Discussion

Regarding ORA's objection to the electric shared assets forecast, we reviewed Exhibit 341 which explains that the allocation of shared assets is based on the causal/beneficial methodology which determines the benefit of an asset to SDG&E according to utilization.⁵¹³ Utilization is in turn determined based on the type of asset and may be in the form of number of users, square footage or other applicable method. The causal/beneficial methods is one of the methods used by Sempra, SoCalGas, and SDG&E to calculate allocation and has been utilized in other portions of the decision such as the section on Corporate Center.

Having determined that the forecast is supported by evidence and testimony, we now focus on which method is more appropriate. Based on our review, we find the causal/beneficial method is more appropriate than ORA's proposal to use a five-year average. We find that use of the causal/beneficial method in this case is more consistent with how SDG&E has approached other allocation issues as seen in other sections of the decision. For the most part,

⁵¹³ Exhibit 341 at ED-13.

SDG&E focuses on an asset by asset approach instead of using historical costs to determine the appropriate allocation and follows a hierarchy of direct allocation, causal/beneficial and then multi-factor method.

Based on the above, we find that SDG&E's forecast method for electric and also gas shared assets is appropriate and that the resulting forecast need not be revised. With respect to the figure presented in witness Vanderhye's testimony, SDG&E explained that the figure was the result of an error which it has corrected.

Concerning the issue of including revenues for the income tax component of contributions in aid of construction, we reviewed ORA's and SDG&E's arguments and agree with SDG&E's position. As explained in SDG&E's testimony and in briefs, D.87-09-026 allows utilities to use either the Maryland Method or Method 5 to address ratemaking treatment of contributions in aid of construction. SDG&E elected to use the Maryland Method while SoCalGas elected to use Method 5. Under the Maryland Method, shareholders bear any gain or loss for any difference between taxes paid and the tax gross-up of the constructed property. Ratepayers therefore are not impacted by the taxes paid and any gross-up so there is no income tax component on contributions in aid of construction under this method. For Method 5, which SoCalGas uses, the tax paid is added to rate base and so the gross-ups in later years are deducted from rate base so there is an income tax component on contributions in aid of construction. Based on the foregoing, we find that no adjustments are necessary to include an income tax component for contributions in aid of construction for SDG&E.

With respect to the rest of the accounts, we reviewed each forecast and the supporting testimony. We do not disagree with the forecast methods utilized

and find the forecasted amounts for each account to be reasonable. We find that the activities performed in each account are generally routine business activities that SDG&E has been performing in prior GRC periods. The revenues forecast in TY2019 for the different accounts generally do not differ too much from 2016 levels. Based on our review, we find that the forecast for these accounts should be adopted and SDG&E's forecast for Miscellaneous Revenues of \$14.653 million for the electric department and \$2.843 million for the gas department should be adopted.

43. Regulatory Accounts

This section addresses the Regulatory Accounts proposals of SDG&E and SoCalGas. Applicants' requests include the disposition of balances, closure, continuation, and modification of existing regulatory accounts, and the creation of new regulatory accounts. Many of these proposals have already been reviewed, discussed, and addressed as part of the discussion of other topics that the regulatory account addresses. For example, the Pension Balancing Account is discussed in the Pension section of the decision. In such cases, this section merely provides reference to the section of the decision where discussion of the account occurred. For convenience, acronyms for regulatory accounts that have already been discussed in other sections of the decision are redefined here.

43.1. SoCalGas

43.1.1. Disposition of Regulatory Account Balances

43.1.1.1. Research Development and Demonstration Expense Account (RDDEA)

Amortization of the overcollection balance under the RDDEA is discussed in section 22.3. under Customer Services Office Operations. We also find SoCalGas' request to transfer any residual balance to the Core Fixed Cost

Account (CFCA) and Noncore Fixed Cost Account (NFCA) and to thereafter eliminate the account reasonable.

**43.1.1.2. Distribution Integrity Management
Program Balancing Account (DIMPBA)**

The DIMPBA is a two-way balancing account that records the difference between actual costs versus authorized amounts for DIMP. SoCalGas requests to amortize the \$3.7 million overcollection balance recorded in the DIMPBA in customers' gas transportation rates. SoCalGas also requests to transfer any residual balances at the end of the amortization period to the CFCA and NFCA and to thereafter close the 2012 to 2015 program cycle. We reviewed SoCalGas' request and find it to be reasonable.

**43.1.1.3. Energy Data Request Memorandum
Account (EDRMA)**

Recovery of account balances under the EDRMA is discussed in section 22.3. under Customer Services Office Operations. We also find SoCalGas' request to transfer any residual balance to the CFCA and NFCA and to thereafter eliminate the account reasonable.

**43.1.1.4. Operational Flow Cost Memorandum
Account (OFCMA)**

Discussion regarding recovery of the OFCMA balance can be found in section 15 under the section on Gas Control and System Operations and Planning. Recovery over a two-year period to provide a gradual increase in rates was deemed appropriate. We also find SoCalGas' request to transfer any residual balance to the CFCA and NFCA and to thereafter eliminate the account reasonable.

43.1.1.5. Fire Hazard Prevention Memorandum Account (FHPMA)

The FHPMA recorded costs associated with fire hazard prevention from 2009 to 2011. Fire hazard prevention costs are no longer recorded in the FHPMA as of January 1, 2012 but a balance totaling \$2.4 million has not yet been recovered. The costs recorded in the FHPMA included activities relating to the installation of weather stations, electrical equipment, and system upgrades for “Red Flag”⁵¹⁴ conditions. The balance is composed of \$1.8 million of O&M expenses, \$0.5 million of capital-related costs and \$0.1 million of interest. Recovery of the recorded costs was authorized in D.12-01-032⁵¹⁵ and we find the request to recover the balance in the FHPMA to be reasonable and approve it. The FHPMA ending balance includes depreciation, taxes, and returns on the FHPMA activities completed in 2009-2011. However, we find it reasonable to deduct \$0.1 million representing interest as we find that SoCalGas should have sought recovery of the FHPMA balance in an earlier proceeding following issuance of D.12-01-032 on January 12, 2012 and SoCalGas did not explain why it is only seeking recovery of the FHPMA balance now.

43.1.1.6. Advanced Meter Opt-Out Program Balancing Account (AMOPBA)

The AMOPBA records incremental costs to implement the AMI Opt-Out Program and associated revenues. SoCalGas requests to amortize the balance in the account which is \$0.2 million in overcollections as of the end of 2018. We

⁵¹⁴ According to SoCalGas, Red Flag declaration conditions are: (a) non-living fuel moisture less than 10 percent; (b) living fuel moisture less than 75 percent; (c) relative humidity less than 20 percent; (d) wind speed sustained at or greater than 30mph or 25mph with 55mph gusts; and (e) Red Flag Warning is issued by the National Weather Service.

⁵¹⁵ D.12-01-032 OP 14 at 180 to 181.

find SoCalGas' proposal to be appropriate as well as the request to eliminate the account since opt-out costs and revenues have been included in the TY2019 forecasts. Also, any residual balances are to be transferred to the CFCA so the account will no longer be necessary.

43.1.1.7. Aliso Canyon Memorandum Account (ACMA)

Continuation of the ACMA to record additional capital-related costs in excess of \$275.5 million is discussed in section 14 of this decision addressing issues concerning the Aliso Canyon Turbine Replacement. Recovery of the above amounts are subject to a reasonableness review in SoCalGas' next GRC.

43.1.1.8. Aliso Canyon True-Up Tracking Account (ACTTA)

The ACTTA records the benefits associated with Regional Clean Air Incentives Market Trading Credits (RTCs) generated by the Aliso Canyon Turbine Replacement project. SoCalGas requests to discontinue recording benefits to the ACTTA and to amortize any remaining balance as of December 31, 2018. We reviewed SoCalGas' proposal and find it to be appropriate as forecasted ACTTA benefits for this GRC period beginning January 1, 2019 have been incorporated into the O&M and other benefits for TY2019. SoCalGas' forecast of \$0.3 million in O&M benefits and \$1.5 million in air emission cost savings are included in Exhibit 277.⁵¹⁶

⁵¹⁶ Exhibit 277 at DLB-32 to 34.

43.1.2. Closure of Existing Regulatory Accounts

43.1.2.1. FERC Settlement Proceeds Memorandum Account (FSPMA)

Pursuant to D.03-10-087, the FSPMA was created to track proceeds from the 2003 Settlement between the State of California and El Paso Natural Gas Company that can be allocated to core aggregation transportation (CAT) customers. According to SoCalGas, it has received all settlement proceeds that can be allocated to CAT customers as a result of the energy crisis.⁵¹⁷ Thus, we agree that there is no further need to keep this account open. In addition, no settlement proceeds have been received or recorded since 2014. SoCalGas also proposes to transfer any residual balance due to variances in sales throughput to the CFCA. This residual balance shall continue to be amortized to CAT customers annually.

43.1.2.2. Deductible Tax Repairs Benefits Memorandum Account (DTRBMA)

The DTRBMA was established in 2015 and tracks the revenue requirement difference associated with the effect on SoCalGas' income tax expense of using the authorized revenue requirement based on the percentage repair allowance deduction compared with an alternate accounting method allowed by the IRS for computing repairs deduction for 2015. SoCalGas is forecasting a zero balance as of 2017 but if there are and any residual balances, these will be recorded in the CFCA and NFCA. In addition, activity related to tax repair deductions for 2016 to 2018 will be recorded in the TMA rather than the DTRBMA. Based on the above, we find it reasonable to close the DTRBMA as any existing balances will

⁵¹⁷ Exhibit 181 at RQY-6.

be recorded in the CFCA and NFCA and future amounts will be recorded in the TMA.

43.1.3. Continuation of Existing Regulatory Accounts

43.1.3.1. Pension Balancing Account (PBA) and Post-Retirement Benefits Other Than Pension Balancing Account (PBOPBA)

Continuation of the two-way balancing account for the PBA and PBOPBA are discussed under Pension and PBOB in section 32 of the decision.

43.1.3.2. New Environmental Regulation Balancing Account (NERBA)

Continuation of the two-way balancing account for the NERBA is discussed under Environmental Services in section 25 of the decision.

43.1.4. Modification of Regulatory Accounts

43.1.4.1. Core Fixed Cost Account (CFCA)

The CFCA balances the difference in authorized margin and other non-gas costs allocated to core customers and the revenues intended to recover these costs. D.16-06-046 approved the closure of four branch offices and directed SoCalGas to record net savings from such closure into the CFCA until the net savings are incorporated in SoCalGas' next GRC. Because the aforementioned net savings are incorporated in the TY2019 GRC, we agree with SoCalGas and find it appropriate to discontinue recording net savings due to the closure of four branch offices.

43.1.4.2. Advanced Infrastructure Balancing Account (AMIBA)

The AMIBA has been extended through 2018 to complete the deployment and post-deployment phases for AMI. SoCalGas will continue to record deployment and post-deployment costs in the AMIBA deployment and post-deployment subaccounts and will request recovery of account balances in

its annual regulatory account update filing and request closure of the two subaccounts. For TY2019, AMI⁵¹⁸ post-deployment costs are already incorporated under Customer Services Field & Meter Reading costs and we find SoCalGas' request to discontinue recording such costs in the AMIBA subaccounts to be reasonable and approve it.

43.1.4.3. Discontinuation of Service Establishment Changes (SEC)

Denial of SoCalGas' request to eliminate the SEC is discussed in section 42 of the decision under the section on Miscellaneous Revenues.

43.1.4.4. Transmission Integrity Management Program Balancing Account (TIMPBA) and DIMPBA

Costs tracked by these balancing accounts are discussed in section 16 of the decision under Pipeline Integrity. Recovery for TIMP and DIMP costs are currently subject to a mechanism where SoCalGas must file a Tier 3 advice letter for undercollections up to 35 percent and an application for undercollections above 35 percent of its authorized O&M and capital expenses including the capital compounding. The current recovery method for TIMP, DIMP, and SIMP results in a compounding effect because capital costs are balanced over the life of the asset and not on a year-to-year basis. SoCalGas proposes to change the method by which the percentage is calculated by applying it against the total authorized O&M and capital expenditures. Thus, for undercollection up to 35 percent of the total O&M and capital expenditures authorized, SoCalGas will

⁵¹⁸ Per Ms. Marelli's Direct Testimony (Ex. 119 (SCG Marelli Revised Direct) at GRM-5), AMI deployment was to be completed by TY2019, therefore no deployment costs were included in the Customer Services Field & Meter Reading forecast. The forecasted costs related to AMI are for post-deployment or operations work only.

file a Tier 3 advice letter and an application for undercollection greater than 35 percent to seek recovery. We reviewed SoCalGas' proposal and find it reasonable. SoCalGas explains that the current method results in a compounding effect because capital costs are balanced over the life of the asset and not on a year-to-year basis. Thus, in a GRC cycle, balancing capital costs in the 1st PTY would include capital costs during the TY and for the 2nd PTY, costs include for that year plus costs during the TY and 1st PTY. Parties do not object to the proposal and we find that the modification should be approved.

**43.1.4.5. Storage Integrity Management Program
Balancing Account (SIMPBA)**

Continuation of the two-way SIMPBA is discussed in the Underground Storage portion in section 13 of this decision. In addition, SoCalGas requests the same modification requested for the TIMPBA and DIMPBA with respect to the calculation of the undercollection percentage and for similar reasons, we find that this request should be approved.

43.1.5. Creation of New Regulatory Accounts

**43.1.5.1. Pipeline Safety Enhancement Plan
Balancing Account (PSEPBA)**

As discussed in section 17, authority to establish the PSEPBA was denied in this decision. SoCalGas is instead authorized to establish a PSEP memorandum account to track PSEP costs and request recovery of amounts in excess of the amounts authorized in this decision.

**43.1.5.2. Morongo Rights-of-Way Memorandum
Account (MROWMA)**

Establishment of the MROWMA is discussed under Gas Engineering in section 12 of the decision. Pre-construction costs in prior periods covered in this GRC should be excluded.

43.1.5.3. Morongo Rights-of-Way Balancing Account

Denial of authority to establish the MROWBA is discussed under Gas Engineering in section 12 of the decision. Costs proposed to be recorded in the MROWBA should instead be tracked in the MROWMA.

43.1.6. Informational Discussion of Other Regulatory Accounts

43.1.6.1. Tax Memorandum Account (TMA)

The TMA was created to track revenue differences resulting from the income tax expense approved in SoCalGas' TY2016 GRC and accrual tax expense incurred from 2016 to 2018. The TMA was created pursuant to D.16-06-054.

43.1.6.2. Compression Balancing Account (CSBA), Biogas Conditioning-Upgrading Services Balancing Account (BCSBA), and Distributed Energy Resources Services Balancing Account (DERSBA)

These three accounts were created pursuant to D.12-12-037, D.13-12-040, and D.15-10-049 respectively to record costs embedded in the GRC used in providing each of these tariffed services.⁵¹⁹

43.1.6.3. Master Meter Balancing Account (MMBA)

The MMBA records costs associated with conversion of master-metered service at mobilehome parks to direct utility service. According to SoCalGas, all "to the meter" assets placed in service through 2016 have been included in rate base and the MMBA will stop recording capital-related costs associated with

⁵¹⁹ Exhibit 181 at RQY-20.

such assets. However, assets placed under service after 2016 will continue to be balanced in the MMBA.

43.2. SDG&E

43.2.1. Closure of Existing Regulatory Accounts

43.2.1.1. Assembly Bill (AB) 802 Memorandum Account (AB802MA)

As discussed in section 22.5., recovery of AB802MA balances is being authorized in this decision as well as the request to close the account.

43.2.1.2. Alternative Fuel Vehicle Memorandum Account (AFVMA)

As discussed in section 22.5., recovery of AFVMA balances is being authorized in this decision as well as the request to close the account.

43.2.1.3. Community Choice Aggregation Implementation Balancing Account (CCAIBA)

The CCAIBA records costs associated with the development of the Community Choice Aggregation program. No costs have been recorded in this account since its inception and so we find SDG&E's proposal to close the account reasonable and grant it.

43.2.1.4. California Solar Initiative Performance-Based Incentive Memorandum Account (CSIPMA)

The CSIPMA records costs related to implementation and administration of an on-bill mechanism to pay performance-based incentive payments related to the California Solar Initiative Program. No costs have been recorded in this account since its inception and so we find SDG&E's proposal to close the account reasonable and should be granted.

43.2.1.5. DTRBMA

SDG&E's DTRBMA is similar to SoCalGas' DTRBMA. The account was established in 2015 and tracks the revenue requirement difference associated with the effect on SoCalGas' income tax expense of using the authorized revenue requirement based on the percentage repair allowance deduction compared with an alternate accounting method allowed by the IRS for computing repairs deduction for 2015. SDG&E states that there is currently a \$10.383 million overcollection balance for electric and \$0 for gas. SDG&E proposes to transfer the above balance to the Electric Distribution Fixed Cost Account (EDFCA) and close the account thereafter. Parties do not object to SDG&E's proposal which we find to be reasonable.

43.2.1.6. EDRMA

As discussed in section 22.5., recovery of EDRMA balances is being authorized in this decision as well as the request to close the account.

**43.2.1.7. Non-Residential Submetering
Memorandum Account (NRSMA)**

The NRSMA records costs related to the implementation of the non-residential customers sub-metering program. No costs have been recorded in this account since its inception and so we find SDG&E's proposal to close the account reasonable and should be granted.

**43.2.1.8. Residential Disconnect Memorandum
Account (RDMA)**

Recovery of account balances under the RDMA is discussed in section 22.3. under Customer Services Office Operations. We also find SDG&E's request to transfer any residual balance to the CFCA and NFCA and to thereafter eliminate the account reasonable.

**43.2.1.9. Real-Time Energy Metering
Memorandum Account (RTEMMA)**

The RTEMMA records costs associated with the Real-Time Energy Metering program. No costs have been recorded in this account since its inception and so we find SDG&E's proposal to close the account reasonable and should be granted.

**43.2.1.10. Smart Meter Opt-Out Balancing
Account (SMOBA)**

As discussed in section 22.2., recovery of SMOBA balances is being authorized in this decision as well as the request to close the account.

**43.2.2. Continuation of Existing Regulatory
Accounts**

43.2.2.1. FHPMA

SDG&E's FHPMA is similar to SoCalGas' FHPMA which is discussed in the SoCalGas section. SDG&E proposes to continue this account and we find the request to be reasonable and should be approved. Similarly, SDG&E accumulates interest on the account dating back to 2010. As we determined in SoCalGas, we find it reasonable to deduct \$44,712 for the accumulated interest.

43.2.2.2. NERBA

SDG&E's NERBA is similar to SoCalGas' NERBA and continuation of the two-way balancing account for the NERBA is discussed under Environmental Services in section 25 of the decision.

43.2.2.3. PBA and PBOPBA

The PBA and PBOPBA accounts for SDG&E and SoCalGas are the same insofar as what the accounts track and record and continuation of the two-way balancing account for the PBA and PBOPBA are discussed under Pension and PBOB in section 32 of the decision.

**43.2.2.4. San Onofre Nuclear Generation Station
Balancing Account (SONGSBA)**

Continuation of the two-way balancing account treatment for the SONGSBA is discussed in section 20 of the decision under Electric Generation.

**43.2.3. Modification of Existing Regulatory
Accounts**

**43.2.3.1. New Energy Metering Aggregation
Memorandum Account (NEMAMA)**

The NEMAMA tracks costs associated with the Net Energy Metering Aggregation Program where eligible customers with multiple meters may elect to aggregate the electrical load of the meters. SDG&E proposes to resolve the disposition of account balances of the NEMAMA in its GRC proceeding or another proceeding deemed appropriate. We reviewed SDG&E's proposal and find it appropriate for the NEMAMA account balances to be addressed in SDG&E's GRC proceedings.

43.2.3.2. TIMPBA and DIMPBA

SDG&E's TIMPBA and DIMPBA are similar to SoCalGas' TIMPBA and DIMPBA. Costs tracked by these balancing accounts are discussed in section 16 of the decision under Pipeline Integrity. SDG&E seeks the same modification for the two accounts requested by SoCalGas as discussed in the SoCalGas section with respect to the calculation of the undercollection percentage and the corresponding recovery mechanism that would be applicable. For similar reasons discussed in the SoCalGas section on TIMPBA and DIMPBA, we find SDG&E's request to be reasonable and should be approved.

**43.2.3.3. Tree Trimming Balancing Account
(TTBA)**

Modification of the TTBA from a one-way to a two-way balancing account is discussed and authorized in section 21 of the decision under the Electric

Distribution section. However, SDG&E is required to file a Tier 3 advice letter for recovery of undercollections up to 35 percent and an application for undercollections above 35 percent.

43.2.4. Creation of New Regulatory Accounts

43.2.4.1. LIPBA

SDG&E's LIPBA is similar to SoCalGas' LIPBA and authority to establish this account is discussed in section 30 of the decision under the section on Corporate Center Insurance.

43.2.4.2. Otay Mesa Acquisition Balancing Account (OMABA)

Authority to establish the OMABA is discussed in section 20 of this decision under the Electric Generation section. The mechanics for the OMABA authorized in section 20 differs slightly from what SDG&E proposed.

43.2.5. Informational Discussion of Other Regulatory Accounts

43.2.5.1. TMA

SDG&E's TMA is similar to SoCalGas' TMA which is discussed in the SoCalGas section. The TMA was created to track revenue differences resulting from the income tax expense approved in SoCalGas' TY2016 GRC and accrual tax expense incurred from 2016 to 2018. The TMA was created pursuant to D.16-06-054.

43.2.5.2. MMBA

SDG&E's MMBA is also similar to SoCalGas' and records costs associated with conversion of master-metered service at mobilehome parks to direct utility service. According to SoCalGas, all "to the meter" assets placed in service through 2016 have been included in rate base and the MMBA will stop recording capital-related costs associated with such assets. However, assets placed under service after 2016 will continue to be balanced in the MMBA.

44. Summary of Earnings

This section presents the total proposed revenue requirements of SDG&E and SoCalGas and the RO model that calculates and compiles all the cost estimates set forth in these GRC proceedings. The revenue requirement is the amount of revenue the utility needs to earn in a test year in order to provide adequate service to its customers and a fair return for its shareholders. Applicants' respective RO calculation are presented in an income statement format which sets forth the estimated amounts needed for each utility to continue to provide safe and reliable utility services and at the same time earn an authorized rate of return on their investment.

The table below shows the total revenue requirements requested by each company and adjustments reflecting the impact of reduced taxes pursuant to the Tax Cuts and Jobs Act which was signed into law on December 22, 2017. Accumulated balances for regulatory accounts are not included in these totals as well as commodity costs for gas which are addressed in the TCAP proceeding

	SDG&E	SoCalGas
Revised Testimony	\$2,198,718,000	\$2,989,477,000
Tax Cuts & Jobs Act reduction	(57,744,000)	(58,685,000)
Reverse Impact of Reduction ⁵²⁰	\$57,744,000	0
Total Revenue Requirement⁵²¹	\$2,198,718,000	\$2,930,792,000

⁵²⁰ The requested offsetting adjustment of \$57.744 million to reverse the impact of the Tax Cuts and Jobs Act is discussed in the Administrative and General section.

⁵²¹ Total Revenue Requirement revised to \$2,202,534,000 for SDG&E and \$2,936,606,000 for SoCalGas in the Update Testimony (Exhibit 514) at B-1 and A-1, respectively.

44.1. RO Calculation Elements

The elements of the RO calculation for SDG&E and SoCalGas are the same which we briefly describe below. No modifications have been made to the RO model since the filing of the previous GRC (TY2016).

Revenue Requirement

Represents the total O&M and capital related costs necessary to support rate base. It is collected from two main components which are base margin and miscellaneous revenues. Base margin are revenues collected from customers for electric and gas utility services.

Miscellaneous Revenues

Fees and revenues collected for services from non-rate sources and any revenues returned to ratepayers pursuant to prior Commission decisions.

O&M Expense Estimates

The utilities' forecast of all costs associated with operating and maintaining its gas and electric services. O&M costs are recorded as expenses on Applicants' balance sheet.

Capital-Related Costs

Costs incurred to acquire or improve a long-term asset with the expectation of receiving larger benefits for longer than a single tax year. Capital costs are recorded as assets on Applicants' balance sheet.

Rate of Return

The profit that Applicants are authorized to earn on rate base or Applicants' capital investment over a period of time. The currently authorized

rate of return by the Commission is 7.55 percent for SDG&E and 7.34 percent for SoCalGas.⁵²²

44.2. Discussion

Applicants' RO model is widely accepted by parties as being able to adequately calculate the revenue requirements for SDG&E and SoCalGas. We have reviewed the testimony concerning the RO model and do not raise any objections or find it necessary to direct any alterations or redesign thereof. This is the same RO model used and adopted during the TY2016 GRC cycle. Therefore, we find that the proposed RO model should be adopted.

In its testimony, ORA recommended an adjustment to the Corporate Center allocations being proposed to reflect Sempra's purchase of Oncor. This recommendation, along with various recommended adjustments to Applicants' proposed O&M, Capital, and Miscellaneous Revenue totals are discussed in the appropriate sections of this decision. The discussion regarding Oncor can be found in the Corporate Center General Administration section of the decision and more specifically in section 29.4.

45. Post-Test Year Ratemaking

PTY ratemaking is the ratemaking framework or mechanism to provide Applicants with an appropriate level of authorized revenues for attrition years 2020 and 2021 in order to address increases in and additional costs due to inflation and capital investments. Applicants also requested the addition of attrition year 2022 to their current rate cycle and this request is addressed in section 5 of the decision.

⁵²² D.17-07-005 and Advice Letters 3120-E and 5192-G.

45.1. Applicants' Proposal

Both SDG&E and SoCalGas propose the application of separate attrition rates for O&M and capital-related revenue requirements. The mechanism to address O&M attrition rates is further subdivided into two different methods to address escalation of labor and non-labor costs versus medical costs.

Applicants propose that:

- a. Labor and non-labor costs be based on the IHS Markit Global Insight forecast;
- b. Medical costs be based on the Willis Towers Watson forecast; and
- c. Capital investments be based on an escalated five-year average of capital additions and for SoCalGas, a forecast of PSEP capital additions beyond TY2019.

The proposed revenue requirement increases from TY2019 are as follows:

	2020		2021	
SDG&E	\$151.5 million	+6.89%	\$120.0 million	+5.10%
SoCalGas	\$236.9 million	+8.08%	\$192.9 million	+6.09%

In addition, both Applicants propose the continuation of the currently authorized Z-Factor mechanism.

45.2. Positions of Intervenors

45.2.1. ORA, FEA, and Long Beach

ORA's main proposal is for a uniform 4.0 percent increase to be applied to PTY2020 and 2021. Alternatively, if Applicants' proposal for separate attrition rates for O&M and capital is deemed reasonable by the Commission, then ORA's alternate proposals are as follows: ORA agrees with basing labor and non-labor costs on the IHS Markit Global Insight forecast but with a 1 percent cap on updates to escalation rates except for medical costs; for medical costs, ORA proposes that an annual increase of 4.25 percent be applied; and for capital additions, ORA proposes a seven-year average. ORA agrees with the

continuation of the Z-Factor mechanism but proposes that it should only be applied to the PTYs.

FEA agrees with ORA's main proposal of a uniform 4.0 percent increase and the seven-year average if the Commission were to adopt separate attrition rates for O&M and capital additions.

Long Beach recommends that annual PTY increases be based on CPI plus additional revenue for forecasted PSEP capital additions.

45.2.2. UCAN

UCAN's main proposal for the PTY mechanism is to apply the CPI-Urban annual increase plus 75 basis points. Alternatively, UCAN agrees with ORA's proposal of a uniform 4.0 percent increase and as another alternative, UCAN proposes that Applicants' proposal incorporate escalated capital additions and retirements based on recorded data from 2013 to 2017. Finally, UCAN also recommends that the 2022 revenue requirement be adjusted to reflect benefits from the CIS Replacement Program.

45.2.3. TURN

TURN proposes to increase ARAM in the attrition years.

45.3. Discussion

We have reviewed Applicants' proposal and the various alternatives presented by different parties. We reviewed the testimony presented, discussions during the hearings, and the positions and arguments raised regarding this topic on brief.

Based on the above review, we find that the main factors affecting projected increases in costs anticipated during the PTYs are dissimilar with respect to O&M and capital additions. We agree with Applicants that the PTY mechanism for capital additions should reflect projected capital additions rather

than just escalation. We also find that applying a percentage increase that is based on the Consumer Price Index (CPI) does not reflect how utilities incur costs. Since O&M expenses and capital expenditures affect the revenue requirement differently, we find that a two-part attrition mechanism, where O&M expenses and capital-related revenues are separately escalated, is reasonable. Therefore, we find it reasonable to apply different PTY mechanisms for O&M and for capital additions.

However, we find that it is not necessary to further subdivide the PTY mechanism for O&M into labor and non-labor, and medical costs. While we do not necessarily disagree with Applicants that medical costs are expected to increase faster than general utility cost inflation⁵²³ or broad-based inflation in the general economy,⁵²⁴ the forecast for O&M costs is a forecast of the average increase in costs. Thus, there should be categories of costs that are higher than the average as well as costs that fall below the average. Applicants focused their testimony and arguments in support of their proposed escalation rates for medical costs to be applied for the attrition years and did not fully justify why medical costs should be treated differently from other O&M costs. We therefore find it reasonable to apply the PTY mechanism deemed appropriate for O&M costs to medical costs as well.

In addition, we also find that the PTY amounts for 2020 and 2021 should be reflected as a single figure which combines the separate analyses for Labor and non-labor O&M costs and costs for capital additions.

⁵²³ Exhibit 242 at JAM-6.

⁵²⁴ Exhibit 245 at KJD-5.

The next subsections discuss the appropriate PTY mechanisms for O&M and capital additions followed by analysis of the Z-Factor mechanism.

45.3.1. O&M Adjustment

We have reviewed the evidence presented and analyzed the positions and arguments of the various parties that provided input regarding this issue and we agree with Applicants that the basing labor and non-labor costs on the IHS Markit Global Insight forecast is more appropriate in this instance.

We find that Global Insight escalation rates are specific to the utility industry and more accurately reflects SDG&E's and SoCalGas' inflationary cost increases. In contrast, escalation based on CPI, which is a broad wholesale pricing index, reflect price increases for goods and services in general and does not sufficiently capture the O&M escalation inputs of SDG&E and SoCalGas. Based on the above, we find that Global Insight escalation rates more accurately reflect SDG&E's and SoCalGas' inflationary cost increases and that their proposed O&M escalation rates should be adopted.

45.3.2. Capital Additions Adjustment

With respect to the proposed adjustment for capital additions, we agree with Applicants' proposal to adjust rate base and associated revenue requirements during the PTYs to reflect the impact of capital additions. We reviewed Applicants' proposed methodology for calculating the PTY adjustment for capital additions and find the methodology to be reasonable except for the proposal to base PTY computations on a five-year average using recorded and forecasted capital additions for 2015 to 2019.

We find that using a seven-year average using recorded and forecasted capital additions for 2013 to 2019 more reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the

evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy.⁵²⁵

While we agree with Applicants' forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives, it is not certain at this point in time at what level these activities will continue to increase and whether or not and at what point additional spending efficiently matches the amount of risk reduction and increased safety. Thus, we find that it is also important to incorporate historical adjustments. A seven-year average provides a more effective normalization of capital additions.

In their alternate proposals, ORA and FEA agree with the use of a seven-year average, while UCAN's alternate proposal was to utilize a five-year average using recorded costs from 2013 to 2017. A seven-year average using both recorded capital additions from 2013 to 2016 as well as forecasted capital additions from 2017 to 2019 balances UCAN's alternate proposal to rely on recorded capital additions and Applicants' position to consider forward-looking additions. For 2017, for purposes of this section only, we agree with Applicants that it would be overly complicated to update certain items for 2017 actuals while leaving other items as forecast and so it is reasonable to apply forecasted capital additions for 2017 to 2019 since certain 2017 information was not yet available when the application was prepared.

⁵²⁵ Exhibit 242 at JAM-7 and Exhibit 245 at KJD-7.

With respect to the proposed methodology to calculate the adjustment for capital additions, we find Applicants' proposal to escalate capital additions by major plant category for each year to PTY dollars based on Global Insight indices to be reasonable. No party objected to this methodology and in the case of ORA, FEA and UCAN, there was no objection in their alternate proposal. Using this methodology, recorded and forecasted costs would be escalated to 2019 dollars and then averaged while additions for 2020 to 2021 are determined by escalating the seven-year average using the Global Insight indices.

45.3.3. Impact of AB 1054 on PTY Capital Expenditures

AB 1054 (Stats. 2019, ch. 79) was signed into law by Governor Newsom on July 12th, 2019. Among the many items addressing catastrophic wildfires, AB 1054 includes a provision that prohibits SDG&E (and other large electrical corporations) from including its allocated share of fire risk mitigation capital expenditures in equity rate base. Specifically, AB 1054 added section 8386.3(e) to the Public Utilities Code to read:

The commission shall not allow a large electrical corporation to include in its equity rate base its share, as determined pursuant to the Wildfire Fund allocation metric specified in Section 3280, of the first five billion dollars (\$5,000,000,000) expended in aggregate by large electrical corporations on fire risk mitigation capital expenditures included in the electrical corporations' approved wildfire mitigation plans. An electrical corporation's share of the fire risk mitigation capital expenditures and the debt financing costs of these fire risk mitigation capital expenditures may be financed through a financing order pursuant to Section 851, subject to the requirements of that financing order.

Further, Pub. Util. Code § 3280 specifies an allocation ratio of 4.3 percent of the \$5 billion aggregate capital amount to SDG&E. Therefore, SDG&E is specifically required by AB 1054 to exclude \$215 million of approved fire risk

mitigation capital expenditures from equity rate base. Consequently, beginning in PTY2020, SDG&E is hereby directed to adjust its PTY revenue requirements to reflect the equity rate base exclusion required by AB 1054. SDG&E is further directed to file a Tier 3 Advice Letter concurrent with its year-end adjustment filing for 2019, providing a detailed explanation and showing of the revenue requirement impact of the section 8386.3(e) equity rate base exclusion when it makes its annual PTY revenue requirement implementation filings.

45.3.4. Z-Factor Mechanism

The Z-Factor mechanism uses a series of eight criteria outlined in D.94-06-011 to identify exogenous cost changes that qualify for rate adjustments prior to the next GRC test year if all eight criteria are met.⁵²⁶ Rate adjustments are allowed for only the portion of Z-Factor costs not already contained in the annual revenue requirement and only for costs that exceed a \$5 million deductible per event.⁵²⁷ No changes are being proposed to the current Z-Factor mechanism that is in place.

We deem the request reasonable and find that SDG&E and SoCalGas should be authorized to continue their separate Z-Factor memorandum account procedure. Applicants are to notify the Commission's Executive Director by letter in case of a Z-Factor event and provide all information and relevant details surrounding the event. Applicants may then file an application for a revenue requirement supplement if the Z-Factor event exceeds \$5 million.

⁵²⁶ Exhibit 242 at JAM-10 to 11 and Exhibit 245 at KJD-8.

⁵²⁷ *Ibid.*

No parties opposed the continuation of the Z-Factor mechanism as proposed except for ORA which recommended that the Z-Factor mechanism should only be applied to the attrition years.

With respect to ORA's proposal, we find that a Z-Factor event is just as likely to occur during the TY as it does during the attrition years. A key element in a Z-Factor event is that the event is unpredictable and occurs after base rates have been set and there is nothing that differentiates the TY from the attrition years insofar as the possible occurrence of a Z-Factor event. ORA does not specify in these applications why it recommends the exclusion of the TY other than stating that this is consistent with their request in PG&E's TY2014 and TY2017 GRCs both of which were resolved by adopting settlement agreements from parties. Therefore, absent any rationale to exclude a Z-Factor event that may occur during Applicants' TYs, we find it reasonable to reject ORA's proposal and conclude that the Z-Factor mechanism should be applicable to the TY2019 as well as attrition years 2020 and 2021.

45.3.5. ARAM and CIS Benefits

Regarding TURN's proposal to increase ARAM during the attrition years, we agree with Applicants that it is overly complicated to calculate ARAM for the very many plant-related assets on an asset-by-asset basis for the attrition years and so applying the 2019 ARAM calculation to the attrition years is reasonable.

As for UCAN's request concerning the incorporation of benefits derived from the CIS Replacement Program authorized in D.18-08-008,⁵²⁸ this request is

⁵²⁸ D.18-08-008 was issued on August 9, 2018.

moot since this decision is not including 2022 in the rate cycle that is being covered by this decision.

45.3.6. Update Filings for PTYs

SDG&E and SoCalGas shall continue to update their PTY revenue requirements by filing Tier 1 advice letters two months prior to the beginning of each attrition year. Thus, to adjust the revenue requirement for 2020, SDG&E and SoCalGas shall each file a Tier 1 advice letter with the Commission's Energy Division on or before November 1, 2019 with the update to the TY2019 revenue requirement to be effective on January 1, 2020. Similarly, Tier 1 advice letters are to be filed on November 1, 2020 to adjust the revenue requirement for 2021 beginning on January 1, 2021.

46. Presentation of Rate

In this section, we review SDG&E's and SoCalGas' testimonies summarizing the transportation revenue and rate changes that would result from adoption of their respective TY2019 GRC proposals, the average bill impacts, and proposed cost allocation methods for new regulatory accounts. This section will also address affordability concerns raised by several parties.

46.1. SoCalGas

Exhibit 349 contains SoCalGas' summary of present and proposed gas transportation revenue and rates. The testimony states that SoCalGas' proposals, if approved, would lead to changes in total authorized base margin, franchise fee rate, uncollectible rate, and balances for amortization in rates of certain regulatory accounts. These topics are more particularly reviewed and addressed in other sections of the decision. The testimony also contains several tables showing revenue, rates, and customer bill impact comparisons for current and

proposed rates for different customer classes. In section 3.2 of the decision, we provided the average bill impact for residential customers for average usage.

The testimony also includes cost allocation methods for new regulatory accounts. These regulatory accounts are discussed in section 43 of the decision. Generally, SoCalGas proposes to allocate balances in the new regulatory accounts using the Equal Percent Authorized margin (EPAM) method. For the ACMA and ACTTA, SoCalGas proposes to allocate costs using the same allocation method used to allocate the Aliso Canyon Turbine Replacement cost cap authorized in D.13-11-023. For the AMOPBA, SoCalGas proposes to allocate across core customer classes using each core customer class.

46.1.1. Positions of Intervenors

CFC, NDC and IS raised similar concerns about the reasonableness of SoCalGas' requests and the reasonableness and affordability of rates resulting from revenue requirement increases in this GRC. NDC adds that continued massive increases in SoCalGas' revenue requirement outpaces ratepayers' ability to afford rates that they charged. IS also suggests that rate increases be limited to projected consumer price index changes as a planning factor for the PTYs except for projects that are needed for safety and risk mitigation.

46.1.2. Discussion

In section 4 of the decision, we stated that our review, analysis, and consideration of the reasonableness of requests made in this GRC considered all the evidence presented, the parties' arguments and positions, as well as the state of the economy and economic outlook described by parties.

Each major cost category was reviewed along with specific O&M and capital requests made in each cost category as well as objections and recommendations by parties. While affordability is of great concern, this must be

balanced with other primary concerns such as safety and risk mitigation, and reliability. We must also consider that utilities should be allowed to earn a fair return on their investment. In reviewing each request, be it O&M or capital related, only necessary projects and reasonable costs are being authorized and so certain expenses and projects were disallowed taking into account various facts, positions, and recommendations raised by various intervenors and also from our own review. We find this approach to be consistent with Public Utilities Code section 451 which requires utilities to provide safe and reliable service at just and reasonable rates. The Commission will continue to carefully evaluate proposed increases in rates in future GRCs.

For its part, SoCalGas states that they prioritize safety and managing risks and that customer bills should also be looked at and not just rates. SoCalGas also adds that their customer bills are low in comparison to other utilities and would remain comparatively low even if the TY2019 proposals are factored in and Exhibit 351 contains tables to illustrate these revenue and customer bill comparisons.

With respect to the proposed allocation methods for new regulatory accounts, we find the general method of allocating balances in these accounts across all customer classes using the EPAM method to be appropriate for the new accounts tracking costs for activities that are likely to benefit all customer classes. We also accept the variations for certain new accounts as these would only benefit certain customers or will utilize a method that the Commission found to be appropriate in a previous decision as is the case for the proposed method for the ACMA and ACTTA.

46.2. SDG&E

Exhibit 350 contains SDG&E's summary of present and proposed gas transportation revenue and rates while Exhibit 352 contains the summary of proposed electric revenue and rates. The above testimonies contain tables showing revenue, rates, and customer bill impact comparisons for gas and electric customers respectively showing current and proposed rates for different customer classes. In section 3.1 of the decision, we provided the combined average bill impact for residential customers for average usage of gas and electricity.

46.2.1. Positions of Intervenors

The issues raised by intervenors are similar to those raised in section 46.1.1 in the SoCalGas portion. In addition, SDCAN states that SDG&E's rates are excessive and that they have leapfrogged rates of other California utilities. SDCAN adds that its rates must be reduced in order to comport with rates of the two other major investor owned utilities in California.

46.2.2. Discussion

Our analysis and discussion in section 46.1.2 (SoCalGas portion) also applies to the affordability issues raised against SDG&E. SDG&E also stated that among the largest utilities in the nation, its monthly residential usage is one of the lowest. This results in low average revenues, and consequently higher than average rates in order to cover a higher allocation of fixed costs. Exhibits 351 and 353 include various tables showing SDG&E's comparative revenues and average customer bills including comparisons with PG&E and SCE⁵²⁹ and we find these

⁵²⁹ Exhibit 351 at ISC-5 and Exhibit 353 Appendix B.

to support SDG&E's claim concerning lower comparative revenues and average monthly residential bills.

Nevertheless, we reiterate that each major cost category as well as requests and proposals under each major cost category were reviewed and only O&M costs and capital projects that are deemed necessary and reasonable based on the evidence presented and arguments raised are being authorized in this decision.

SDCAN also raised issues relating to the rate design of SDG&E's tiered rates and proposed that SDG&E's rates be tied to the rates of PG&E and SCE, but these issues are outside the scope of this proceeding.

47. Results of Examinations (ORA Audit)

ORA conducted an examination of SDG&E's and SoCalGas' financial records pursuant to Sections 314, 314.5, and 309.5 of the PUC Code. The examination is conducted to ensure that the interests of ratepayers are protected and to review Applicants' financial records upon which the GRC is based on, to determine if they are reasonable and proper for ratemaking purposes under established Commission rules and regulations.⁵³⁰

ORA conducted an examination of Applicants' A&G and O&M expenses from 2012 to 2016 in order to review the historical financial data used in forecasting proposed revenue requirement cost components in the GRC applications.

Based on its review, ORA recommends removal of \$968,000 in SDG&E's audit costs and \$670,000 of SoCalGas' audit costs from 2014 to 2016. These costs pertain to 20 attorney-client privileged internal audit reports. ORA also

⁵³⁰ Exhibit 428 at 2.

recommends that SDG&E and SoCalGas continue to submit the Gas Transmission, Distribution, and Storage Safety reports.

Applicants object to the exclusion of the audits and state that costs for the audits are being excluded because ORA was not granted access to the audits and not because the costs were incorrect or imprudent.

47.1. Discussion

As explained in Section 29.3.1.2 of the decision under the Finance section of Corporate Center – General Administration, ORA’s recommended exclusion pertains to costs for 20 audits to which ORA was not granted access. Applicants however, explained that access to these audits was withheld from ORA because the documents are confidential in nature pursuant to the attorney-client privilege. We found Applicants’ explanation to be reasonable and agree that these audits were legitimate expenses for necessary audits and should not be excluded. We reiterate this finding here that these costs should not be excluded. Regarding SDG&E’s and SoCalGas’ Gas Transmission, Distribution, and Storage Safety reports, we agree with ORA’s recommendation that SDG&E and SoCalGas continue to submit these reports without any modification as to the content and timing requirements that are currently imposed.

48. Mobilehome Park Utility Upgrade Program

This section addresses Applicants’ requests relating to expenditures incurred in the Mobilehome Park Utility Pilot Program (MHP Pilot Program).

In D.14-03-021, the Commission directed Applicants to execute the MHP Pilot Program, a three-year program from 2015 to 2017 to convert master-metered and/or sub-metered systems that supply electricity, natural gas or both to mobilehome parks and manufactured housing communities (collectively, MHPs), into direct utility service. Applicants are to convert

approximately 10 percent of spaces in MHP communities within their service territories. The primary purpose of the conversions is safety and secondarily, system reliability and capacity.

D.14-03-021 authorized recovery of reasonable incurred costs⁵³¹ and the MMBA was authorized to record and track “to-the-meter” and “beyond-the-meter” construction costs. To-the-meter costs include contracted labor, purchased services and materials, and trenching, paving, management costs, outreach, planning, and utility labor costs in support of the program such as civil construction, setting meters, gas service turn-on, purging of legacy systems, removal of master meters, and procurement and warehousing of materials.⁵³² On the other hand, beyond-the-meter costs include work related to construction of new utility services from the utility meter to the mobilehome.⁵³³

48.1. SoCalGas

SoCal Gas seeks recovery of \$0.3 million of O&M costs and \$15.5 million of capital costs reflecting costs for the first 32 MHP conversion projects. These were the projects that were completed through 2016. SoCalGas will continue to convert MHPs until 2019. The original scope of the MHP Pilot Program contemplated the conversion of 199 MHPs.

48.1.1. Positions of Intervenors

ORA is the only party that provided comments to this section and ORA does not object to or dispute SoCalGas’ requested recovery amounts.

⁵³¹ D.14-03-021 at 3.

⁵³² Exhibit 354 at JSV-5.

⁵³³ *Ibid.*

48.1.2. Discussion

The requested O&M and capital costs shall be discussed together. The costs being recovered are for completed conversions in 2016 and the MMBA records actual costs. SoCalGas provides a detailed breakdown of costs in table JSV-3 of Exhibit 354.⁵³⁴

We reviewed the breakdown of costs as well as the rest of the evidence presented and find the expenditures to be reasonable. The expenditures are for reasonable construction and related activities in order to convert metered and sub-metered systems to direct utility service pursuant to the MHP Pilot Program. SoCalGas also presented testimony that describes their efforts to reduce costs such as project monitoring, invoice validation, tracking costs versus the original estimate, engaging the services of diverse business enterprises, performing quality assurance checks, establishing a governance plan, and establishing a safety policy. The average cost per space is approximately \$9,833 which is within the estimated per space cost in R.11-02-018 of \$10,703 with a 16.5 percent contingency.⁵³⁵

In view of the above and including consideration of the review that ORA conducted, we find that the requested recovery of \$15.8 million should be approved.

48.2. SDG&E

SDG&E is requesting \$0.2 million for O&M expenses and \$11.3 million for capital costs representing both gas and electric costs for the upgrade of six

⁵³⁴ *Id.* at JSV-13.

⁵³⁵ D.14-03-021 Appendix B.

completed MHP upgrades through 2016. SDG&E will continue to upgrade MHPs until 2019 pursuant to the MHP Pilot Program. The original scope contemplated the upgrade of 30 MHPs.

48.2.1. Positions of Intervenors

ORA is the only party that provided comments to this section and ORA does not object to or dispute SDG&E's requested recovery amounts.

48.2.2. Discussion

As was the case in the SoCalGas discussion, the requested O&M and capital costs shall be discussed together. The costs being recovered are for six completed conversions in 2016 and the MMBA records actual costs. SDG&E provides a detailed breakdown of costs in table JSV-3 of Exhibit 356.⁵³⁶

We reviewed SDG&E's request and find the expenditures being recovered to be reasonable and necessary for the same reasons as explained in Section 48.1.2 during the discussion of SoCalGas' MHP Pilot Program request. The average cost per space \$28,080 for both the gas and electric portion and this amount is within the estimated total per-space cost in R.11-02-018 of \$28,529 which includes a 16.5 percent contingency amount.⁵³⁷

49. Accessibility Issues

This section addresses the joint proposal between Applicants and CforAT regarding accessibility issues (Joint Accessibility Proposal). Details of the Joint Accessibility Proposal are presented in Exhibit 365.

⁵³⁶ Exhibit 356 at JSV-12.

⁵³⁷ D.14-03-021 Appendix B.

49.1. Summary of Major Terms

Under the Joint Accessibility Proposal, Applicants propose to commit to certain terms that are designed to improve accessibility of facilities and services.

Level of Spending

SDG&E and SoCalGas will jointly spend \$1.5 million per year during the TY2019 GRC cycle on eligible activities to improve accessibility. Each utility will spend a minimum of \$450,000 per year.

Disability Access Coordinator

Applicants will either jointly or separately employ a Disability Access Coordinator that will coordinate company-wide strategies to improve accessibility.

Annual Reporting

Utilities will jointly or separately prepare an annual report on activities and spending and will provide a copy of the report to CforAT.

Eligible Activities

Include activities to be performed by the Disability Access Coordinator and activities to improve physical accessibility and communications accessibility. A list of eligible activities under each section is provided in Exhibit 365.⁵³⁸

Term

The commitments in the Joint Accessibility Proposal are to be effective from the effective date of this decision until the end of the TY2019 GRC period or until December 31, 2021.

⁵³⁸ Exhibit 365 at 3 to 7.

49.2. Discussion

We reviewed the proposed Joint Accessibility Program and find that the commitments to be undertaken voluntarily by Applicants are reasonable and in the public interest. The activities described in the joint proposal promote further improvement of access to Applicants' facilities for persons with disabilities that use Applicants' services and facilities. The commitments are also sufficient in scope to establish meaningful access improvements. The proposed improvements also promote public safety and improve customer service.

According to Applicants and CforAT, the Joint Accessibility Proposal can be implemented within the revenue requirements requested in these proceedings. No additional funds are being requested by Applicants to perform their commitments under the Joint Accessibility Program. Thus, funds authorized in this decision for uses and purposes for which they were requested, and which are being authorized in this decision pursuant to those uses and purposes, will not and should not be diverted to fund this program unless there is compelling need to do so.

The Joint Accessibility Proposal is not a formal settlement between Applicants and CforAT and so we need not review the request under the more stringent guidelines required for approving settlement agreements. The Joint Accessibility Proposal is limited in scope to the interest of persons with disabilities and only affects issues that are of concern to Applicants and CforAT. The Joint Accessibility Proposal does not contravene any of the various requests, recommendations, proposals and issues raised by other parties and adoption thereof does not require that any other party to the GRC proceedings agree. The Joint Accessibility Proposal also avoids the need to litigate issues between Applicants and CforAT.

Therefore, in view of all the above, we conclude that the Joint Accessibility Program, as described in Exhibit 365, should be adopted.

50. Category and Need for Hearing

In Resolution ALJ 176-3407 dated October 26, 2017, the Commission preliminarily categorized both applications as ratesetting as defined in Rule 1.3(e) and determined that evidentiary hearings are necessary. We affirm that the category for this proceeding is ratesetting and evidentiary hearings were held from July 9, 2018 to August 8, 2018.

51. Comments on the Proposed Decision

The proposed decision of the ALJ in this matter 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 September 11, 2019 by the following: Sierra Club and UCS; Long Beach; Lancaster; SBUA; UCAN; IS; POC; NDC; SCGC; CUE; TURN; SoCalGas and SDG&E and; ORA. OSA filed its Comments on September 13, 2019.⁵³⁹ Reply Comments were filed on September 16, 2019 by the following: TURN; Sierra Club and UCS; NDC; UCAN; POC; and SBUA on September 16, 2019. The comments raised by various parties were carefully reviewed and considered and appropriate changes to the decision have been made. A number of comments reiterate issues and arguments that were raised previously in testimony and in briefs and these had already been thoroughly analyzed and given careful consideration in the proposed decision. Nevertheless, all Comments and Reply Comments were thoroughly reviewed.

⁵³⁹ OSA's Motion to Late-File its Comments was approved by the ALJ Ruling on September 16, 2019.

52. Assignment of Proceeding

Commissioner Liane M. Randolph is the assigned Commissioner and Rafael Lirag is the assigned ALJ in these proceedings.

Findings of Fact

1. Over 500 exhibits were identified and used during the course of the proceedings.
2. In separate rulings on March 8, 2018 and April 30, the assigned Commissioner ruled that proposed issues concerning lost and unaccounted for gas and whether changes are needed to the reconnection process for gas customers are outside the scope of the proceedings.
3. Rulings were made by the assigned ALJ on July 10, 2018 and September 17, 2018 clarifying that all core balancing issues, storage issues regarding Aliso Canyon, and EDF's requests regarding improvements to backbone transmission and storage services are outside the scope of the GRC proceedings.
4. In the ALJ ruling on June 7, 2018, SDG&E and SoCalGas were authorized to establish separate GRC memorandum accounts to track changes and differences in the revenue requirements that are adopted in these proceedings during the period between January 1, 2019 and the effective date a final decision is adopted.
5. SDG&E and SoCalGas are related companies due to their corporate structure of being subsidiaries of Sempra and because they are in the same business of providing utility services to customers.
6. Shared services are activities performed by one utility (or Sempra's corporate center) for the benefit of the other utility, the corporate center, or an unregulated affiliate company and are allocated and billed to the entity receiving

the service while non-shared services are activities that benefit only the utility performing the activity.

7. These GRC applications are the first by a regulated utility to fully incorporate risk mitigation activities using the risk-informed framework developed by in the S-MAP and RAMP proceedings.

8. The S-MAP, RAMP, and spending accountability process to integrate risk mitigation activities into the GRC are still being refined.

9. Witness testimony that incorporate RAMP-driven requests identify the total amounts associated with RAMP but activities are integrated with O&M and capital requests of individual cost centers.

10. Because the RAMP portion in Applicants' requests is not presented as separate and distinct from the non-RAMP portions, review of funding requests was informed by the RAMP Report but in many instances was based on standard GRC methods such as the quality of the forecast, counterarguments by intervenors, and whether a given showing met the burden of proof.

11. As discussed in the ERM section, Applicants' forecast for ERM costs is reasonable.

12. Pursuant to SB 901, Pub. Util. Code § 706 has been amended such that, beginning January 1, 2019, Applicants are no longer able to recover from ratepayers the annual salaries, bonuses, benefits, or other consideration paid to officers and these must instead be funded by shareholders.

13. Resolution E-4963 was issued requiring SDG&E and SoCalGas to establish respective OCMA's to track compensation paid to an officer beginning January 1, 2019 until closure of the OCMA at the direction of the Commission.

14. Officer compensation and benefits are typically embedded in multiple costs and forecasts presented throughout the GRC.

15. The revision to § 706 became effective after evidentiary hearings had already concluded and briefs had already been filed.

16. Pursuant to D.16-06-054, all costs that have stemmed from the Aliso Canyon gas leak incident are excluded from these GRCs and have been removed from historical cost information utilized by witnesses.

17. The appropriate term for the GRC cycle is currently being considered in R.13-11-006.

18. Reasons for adoption of a four-year GRC cycle do not only apply to SDG&E and SoCalGas.

19. As discussed in the section on Fueling Our Future (FOF), the FOF savings forecasts of SDG&E and SoCalGas are reasonable and costs incurred during the 18-week Project Phase fall within the umbrella of activities included in FOF.

20. As discussed in the Gas Distribution section, a historical linear trend to develop costs for Locate and Mark, Measurement & Regulation, and Cathodic Protection is appropriate and the forecasts for these are reasonable.

21. The number of miles used by SoCalGas to forecast the Aldyl-A Survey is lower than the current data.

22. As discussed in the Gas Distribution section, the forecasts for Asset Management, Regional Public Affairs, and Operations and Management are reasonable.

23. The rate case plan requires that the GRC application use the most recent data available at the time the application is filed which in this case is the base year or 2016 data.

24. Historical costs for Main Maintenance, Service Maintenance, and Tools, Fittings & Materials have been fluctuating.

25. The incremental costs for Service Maintenance are justified.

26. Recorded costs from 2015 to 2017 are more reflective of current costs for Field Support.

27. Additional work anticipated for SB 661 is already included in the forecast for Locate & Mark.

28. Funding for the Bi-Annual High-Pressure Leak Survey is required by GO 112-F and supports risk mitigation activities pursuant to reducing the RAMP risk of Catastrophic Damage Involving High-Pressure Pipeline Failure.

29. It is not feasible or practical to constantly update data for the entire application because of the vast amounts of data included in the application.

30. There are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and the Commission should exercise its discretion in doing so in appropriate cases.

31. As discussed in section 7.1.3.17, SoCalGas' proposed capital projects and forecasts for Pressure Betterments, Main Replacements, Measurement & Regulation Devices, New Business, Supply Line Replacements, Service Replacements, Main and Service Abandonments, Regulator Stations, Cathodic Protection, Pipeline Relocations - Freeway, Pipeline Relocations - Franchise, and Other Distribution Projects and Meter Guards are necessary and reasonable.

32. SoCalGas' funding requests for the Capital Tools, Field Capital Support, and Remote Meter Reading capital projects under Gas Distribution are not supported by the evidence as discussed in section 7.1.3.17.

33. Clothing and other gear containing the utilities' name and logo were used for reasonable purposes in connection with safety-related and public events that provide benefits to ratepayers.

34. SDG&E's forecast for Gas Distribution O&M costs are reasonable except for Supervision & Training which the evidence supports reducing as discussed in section 7.2.1.3 of the decision.

35. As discussed in section 7.2.2.15, SDG&E's proposed capital projects and forecasts for New Business, System Minor Additions, Relocations & Retirement, Meter & Regulator Materials, Pressure Betterments, Distribution Easements, Pipeline Relocations - Freeway & Franchise, Tools & Equipment, Code Compliance, Cathodic Protection, and Regulator Stations & Other are necessary and reasonable.

36. The evidence supports modifying SDG&E's funding requests for the Replacement Mains & Services and Local Engineering capital projects under Gas Distribution as discussed in section 7.2.2.15 of the decision.

37. The addition of new refueling stations is not supported by the procurement of additional vehicles and it is reasonable to deny the funding request for CNG Station Upgrades.

38. SoCalGas forecasts for Gas System Integrity are reasonable including the incremental RAMP-related costs.

39. Pursuant to Pub. Util. Code § 591, proposed training discussed under Gas System Integrity must be included in SoCalGas' Risk Spending and Accountability Reports along with a comparison of what was spent and an explanation regarding any discrepancy.

40. SoCalGas and SDG&E are working, on a voluntary basis, towards the implementation of a PSMS following the recommendations in API RP 1173, but implementing a system-wide PSMS must first be reviewed thoroughly, based on sound assessment practices and producing reliable findings, and a detailed plan must be developed before implementation.

41. API RP 1173 is not a required practice and some key elements are already being applied by SoCalGas and SDG&E.

42. Many of OSA's recommendations focus on safety culture enhancements and practices and not revenue requirements.

43. SoCalGas TY2019 O&M forecast for Gas System Integrity is reasonable.

44. The IT-related capital projects requested by SoCalGas under Gas System Integrity are reasonable except for the Click Enhancement Project and the Field Data Collection with eForm project.

45. The Click Enhancement Project and the Field Data Collection with eForm project SoCalGas seek to improve on the existing IT systems but SoCalGas fails to explain why those systems are no longer adequate to complete the same tasks.

46. SDG&E's TY2019 O&M forecast for Gas System Integrity is reasonable.

47. As discussed in the section on Gas Transmission Operations, HCA mitigation and ROW maintenance are activities that were already being performed by SoCalGas prior to the RAMP process and SoCalGas did not sufficiently explain and justify why incremental funding over historical costs is necessary for these two areas.

48. The O&M request by SoCalGas under Gas Transmission Operations for recovery of the North-South project abandonment refers the reader to the capital exhibit.

49. SDG&E's O&M forecast for Gas Transmission Operations is reasonable.

50. The requested amount for Compressor Stations under Gas Transmission capital incorporates delays involving the Blyth Modernization project and RAMP-related expenses for Auxiliary Equipment.

51. The evidence does not support incremental funding for Auxiliary Equipment because base activities in 2017 were around the same as historical levels that did not include incremental RAMP activities.

52. The Scoping Memo in A.13-12-013 for authority to recover costs associated with the North-South project ordered that a CEQA review be conducted and over \$20 million was spent on activities pursuant to CEQA review.

53. D.16-07-015, which rejected the North-South project as well as the proposal to recover project costs, did not exclude any costs that may be recovered, including CEQA costs.

54. CEQA costs for the North-South project were incurred in prior years that fall outside the period of costs that are being considered in this GRC proceeding and there is also no memorandum account or other similar mechanism that set aside consideration of the costs now proposed to be recovered.

55. An abandoned project generally presupposes that the project had been previously authorized or approved which is not the case for a denied project.

56. As discussed in the section on Gas Transmission Capital, SDG&E's forecasts for capital expenses are reasonable except for New Pipeline.

57. A five-year average is more appropriate for New Pipeline similar to the other cost categories where large-scale projects are also being planned for one or more of the years included in this GRC cycle.

58. As discussed in the section of Gas Major Projects, SoCalGas' O&M and capital forecasts for Gas Major Projects are reasonable.

59. As discussed in the Gas Engineering section, SoCalGas' forecast for ROW costs is appropriate because the longer historical period better addresses ROW contractual agreements which are hard to predict.

60. Negotiations to renew the expired and expiring ROWs with Morongo are still ongoing and an agreement can still be reached.

61. The MROWMA will record pre-construction costs associated with the possible relocation of gas transmission pipelines to bypass the Reservation.

62. MROWBA will record costs associated with the renewal of the expiring ROWs as well as pre-construction costs associated with potential relocations that will be incurred beginning January 1, 2019.

63. As discussed in the Gas Engineering section, SoCalGas' shared services O&M forecast for Gas Engineering did not incorporate the reductions to Engineering Design and Engineering Analysis Center recommended by ORA but with this adjustment, the forecast is reasonable.

64. SDG&E's O&M costs for Gas Engineering are captured in SoCalGas' shared services costs.

65. As discussed in the section on Gas Engineering, SDG&E's capital forecasts for Gas Engineering are reasonable.

66. As discussed in the section of Underground Storage, SoCalGas' O&M forecasts for Underground Storage which include incremental costs to address additional regulations from CARB, DOGGR, and PHMSA, are reasonable.

67. Proposed activities for UGS and AGS are routine in nature and a one-way balancing account to track these costs is not necessary at this time.

68. Work relating to SIMP may vary greatly such as proposed regulations that may have a significant impact on costs.

69. SoCalGas should include a SMS proposal for gas storage in its next GRC application.

70. As discussed in the section on Underground Storage, SoCalGas' capital forecasts for Underground Storage projects are reasonable as opposed to ORA's recommendation to use 2017 costs which does not account for project delays.

71. OP 12 of D.13-11-023 provides that after completion of the Aliso Turbine Replacement project, a reasonableness review of project costs as well as efforts to maximize O&M cost savings and capital benefits should be conducted in the following GRC. The project was fully completed and placed into service on May 17, 2018 and this GRC is the GRC described in D.13-11-023 that follows completion of the project.

72. SoCalGas' testimony showing variances for the seven major project cost elements of the Aliso Turbine Replacement and the explanation for the variances is reasonable.

73. As discussed in the section on Gas Control and System Operations and Planning, SoCalGas O&M forecasts for these costs are reasonable and include compliance with the Gas Emergency Management Program required by GO 112.

74. We agree with EDF that the core balancing proceeding only applies to core customers but find that there is only a single process for core balancing to actual demand for both core and non-core customers.

75. Recovery of the \$1.696 million balance tracked in the OFCMA for major system enhancements is reasonable.

76. The six IT-related projects under Gas Control and System Operations are reasonable.

77. The activities associated with TIMP and DIMP are performed pursuant to compliance with regulatory requirements mandated by 49 CFR section 192, Subpart O and Subpart P.

78. TIMP manages risk reduction through assessments and remediation of transmission pipelines while DIMP implements target activities, programs, and projects that provide an extra layer of monitoring, assessment, and proactive remediation.

79. As discussed in the section on Pipeline Integrity for Transmission and Distribution, TIMP and DIMP activities are necessary and the O&M and capital forecasts of SoCalGas and SDG&E are reasonable.

80. SoCalGas' proposed costs and replacement rate in this GRC for the VIPP, BSRP, and DRIP programs are reasonable and within SoCalGas' means to complete although SoCalGas' replacement rate is not on pace with its original assessment.

81. TIMP inspections have been proactively expanded over the years to include non-HCA areas which are beyond the current requirements set forth by Subpart O but SoCalGas should continue to properly prioritize what pipelines are to be inspected.

82. Costs for programs such as VIPP and DREAMS must be balanced with addressing other key safety risks and also with keeping rates affordable.

83. SDG&E's proposed and replacement rate in this GRC for Aldyl-A and DREAMS program pipe replacement are reasonable and within its means to complete although the replacement rate is not on pace with its original assessment.

84. In D.11-06-017, the Commission required operators of natural gas pipelines to file a comprehensive Implementation Plan to replace or pressure test all-natural gas transmission pipeline in California that have not been tested or for which reliable records are not available and provided specific requirements that must be complied with.

85. The Commission authorized SoCalGas' and SDG&E's safety enhancement plan in D.14-06-007 and directed the utilities to begin implementation of the plan but did not pre-approve the proposed budget for the plan and instead developed a review and recovery mechanism wherein costs for individual projects can be approved after-the-fact.

86. In D.16-08-003, SoCalGas and SDG&E were authorized to include in their TY2019 GRC all PSEP costs not subject to prior applications including possible review of any remaining 2018 Phase 1A and 1B capital costs and this GRC is the first that includes any PSEP costs.

87. As discussed in the PSEP section of the decision, PSEP is divided into Phase 1A, Phase 1B, Phase 2A, and Phase 2B projects.

88. Because 2019 is a transition year as PSEP is incorporated into the GRC process, costs presented represent the total costs over the three-year GRC period and not just for the TY.

89. Planning and engineering costs for the proposed PSEP projects that were already incurred prior to 2019 are included in the PSEP Phase 2 Memorandum Account and SoCalGas will seek amortization of these costs in a separate proceeding as authorized under D.16-08-003.

90. ORA developed statistical models for PSEP pressure test and replacement projects based on up to five years of historical cost data from projects by PG&E, SoCalGas, SDG&E, and Southwest Gas Company.

91. ORA's model does not take into account project-specific factors, uses 95 percent of pressure data from PG&E projects, is based on data that does not include projects with a capital component, and utilize mostly Phase 1A data compared to the Phase 1B and Phase 2A projects being proposed in this application.

92. The addition of a risk assessment component to PSEP costs is an industry-recommended practice that aims to increase the quality and accuracy of estimates and is appropriate for the proposed PSEP projects although the proposed contingency factors overinflate the overall costs given SoCalGas' detailed project cost estimates.

93. Line 235 is scheduled for pressure testing in this GRC cycle but is currently out of service because of numerous leaks found on the pipeline.

94. Costs to repair small segments in Line 235 are included in approved TAMP costs as well as in PSEP but it is reasonable that the small non-contiguous portions of the rupture cannot be easily removed from the continuous pressure testing as it would not be cost-effective.

95. The majority of PSEP capital expenditures are expected to close to plant in service in 2020 and 2021 therefore these PSEP capital costs are not fully reflected in the TY2019 revenue requirement.

96. It is almost certain that the 50 percent project completion proposed for Line 44-1008 will not be completed in this GRC cycle.

97. Pub. Util. Code § 957 requires that remote and automatic shutoff valves be installed as quickly as is reasonably possible and it is the Commission's objective that PSEP be completed as soon as practicable.

98. Authority to substitute one or more PSEP projects authorized in this decision with other PSEP projects in cases of delay or when necessary to do so for safety or reliability reasons is reasonable.

99. PSEP cost estimates for the proposed Phase 2A and 1B projects are better developed relative to Phase 1A projects that have been undertaken by SoCalGas and the currently proposed projects also include project contingencies to address some of the cost uncertainties.

100. As discussed in the section on Procurement, the O&M and capital forecasts of SoCalGas and SDG&E under Procurement are reasonable.

101. As discussed in the AMI section, the O&M and capital forecasts for AMI are reasonable and it is proper to include AMIBA balances in rates.

102. SDG&E had contracted for the use of the Otay Mesa power plant subject to a Put and Call Option at the end of the 10-year PPTA which is set to expire on October 3, 2019.

103. The Put Option is exercisable at OMEC's sole discretion and would require SDG&E to purchase the Otay Mesa plant at a set price that would be significantly below the net book value of the Palomar power plant which is smaller in size.

104. The Call Option, which is exercisable at SDG&E's sole discretion, would require OMEC to sell the Otay Mesa plant to SDG&E at a price higher than the price in the Put Option. SDG&E has refused to exercise its rights under the Call Option. OMEC exercised its right under the Put Option but the sale does not become final until October 3, 2019.

105. Resolution E-4981 approved SDG&E's request in Advice Letter 3294-E for a proposed Confirmation between SDG&E and OMEC for local, system and flexible capacity from the Otay Mesa plant between October 3, 2019 through August 31, 2024.

106. POC filed a rehearing application of Resolution E-4981 which was later denied in D.19-08-014.

107. The Put Option to sell Otay Mesa to SDG&E has now been revoked. After the proposed decision was issued in this proceeding, SDG&E informed the Commission that OMEC had rescinded its exercise of the Put Option and that SDG&E was withdrawing its OMEC proposals from this proceeding.

108. Meeting GHG target needs should not be considered as incremental work under Resource Planning given that this has been a relatively longstanding activity that is being performed by SDG&E.

109. Continuation of the two-way SONGSBA is reasonable.

110. As discussed in the Electric Generation section, SDG&E's O&M forecasts are reasonable subject to deducting OMEC costs, incremental work for Resource Planning, and removal of Chamber of Commerce dues in 2016 for Boulder City.

111. SDG&E's proposal to use a general capital budget rather than specific capital projects for Electric Generation allows flexibility and adaptability to meet current and future plant needs in part because of the uncertainty with regards to the OMEC acquisition.

112. TURN identified two projects concerning Palomar that should have been disallowed in 2012 and were still included in the revenue requirement beginning in 2016. SDG&E agrees with the adjustment.

113. As discussed in the Electric Distribution section, the evidence shows that reductions to SDG&E's O&M forecasts for Construction Services, Electric Distribution Operations, Kearny Operations Services, Project Management, Substation Construction and Operations, and Distribution and Engineering are reasonable.

114. A two-way balancing account for Tree Trimming will enable SDG&E to act more quickly in case further activities to mitigate wildfire risk become necessary and at the same time allow SDG&E to return excess funds not utilized to ratepayers.

115. As discussed in the Electric Distribution section, SDG&E's O&M forecasts for Reliability & Capacity, Distribution Operations, Enterprise GIS, Grid Operations, Officer, Electric Regional Operations, Skills and Compliance

Training, Service Order Team, System Protection, Asset Management, Troubleshooting, Vegetation Management (Pole Brushing), Vegetation Management (Tree Trimming), Regional Public Affairs, Major Projects, Technology Utilization, Compliance Management, Technology Solutions and Reliability, Emergency Management, Strategic Planning and Business Optimization, and Distributed Energy Resources are reasonable.

116. SDG&E's PBR mechanism was established based on an agreement between SDG&E and CUE during the TY2012 GRC as a means to improve reliability of SDG&E's electric system by providing financial incentives for reaching target values using the four reliability indices.

117. A PBR mechanism for electric reliability is not a requirement to the GRC application either from Commission rules or the Rate Case Plan but the Commission can choose to adopt one if it finds that doing so will cause a utility to improve performance and thereby increase customer satisfaction or safety.

118. SDG&E's comparative SAIDI and SAIFI values with that of other investor owned utilities are satisfactory.

119. SDG&E also needs to prioritize safety and mitigating risks that also include electric reliability risks identified in the RAMP Report.

120. As discussed in the Electric Distribution section, SDG&E's capital forecasts for Capacity/Expansion, Franchise and Mandated are reasonable.

121. For Capacity/Expansion projects, SDG&E reduced planned projects for 2017 and 2018 in order to account for delay of the Ocean Ranch substation project that was planned for 2019.

122. For Equipment/Tools/Miscellaneous, SDG&E admits that it intended to use the three-year average and not the three-year linear trend and that its forecast for 2018 and 2019 should be reduced as ORA recommends. Costs in

2017 are projected to be higher because of a one-time purchase of new fire retardant garments and safety gear to comply with OSHA requirements.

123. Under New Business, SDG&E provides a brief timeline of the construction process and describes that a developer first submits a development plan which leads to the permitting process. The developer then contacts SDG&E which then performs the distribution capital work. Once this is done, the developer can then construct the building and afterwards, SDG&E can place a meter in the building to measure electric consumption.

124. Based on the construction timeline described by SDG&E, there may be factors between submissions of development plans and distribution capital work, such as delays or issues with the permitting process.

125. Once development plans are submitted, it is still uncertain that distribution work will be performed but once meters are ready to be placed, although some time lag may occur, it is more certain that the distribution work will actually occur.

126. The forecasts for Overhead Pools are impacted by the amount of capital activities to be conducted and so the reasonable amount of SDG&E should Overhead Pools are based on the amount of capital projects that are authorized in this decision as opposed to SDG&E's forecasts.

127. It is reasonable to apply a one-way balancing account treatment to the funding authorized for Overhead Pools to ensure that funds associated with engineering, reliability analysis, preliminary design work, etc. relating to specific capital projects that are cancelled or postponed are not reassigned to other areas.

128. For Reliability/Improvements projects, TURN's proposals to normalize costs for the 4kV Substation Modernization and to extend the replacement period over a longer period of time reasonably minimizes cost impacts to ratepayers.

129. For Safety and Risk Management Projects, TURN's recommendation regarding the SF6 Switch Replacement project, that switches that have remaining useful lives and no leaks might not need to be proactively replaced, is reasonable.

130. For DER projects, the Microgrid for Energy Resilience project may be duplicative of what other proposed projects will achieve and does not provide enough benefits to justify approval of the project.

131. Under Transmission/FERC Driven Projects, the permit for the Del Mar Reconfigure project has not been filed and it is doubtful that the project will be completed in 2019.

132. As discussed in the Electric Distribution section, SDG&E's capital forecasts for Equipment/Tools/Miscellaneous, New Business, Materials, Overhead Pools, Reliability/Improvements, Safety and Risk Management, DER, and Transmission/FERC Driven Projects should be adjusted as described in section 21.2.2.12 of the decision.

133. As discussed in the Electric Distribution section, the following IT-related projects propose enhancements and improvements to existing systems without explaining why the existing systems are inadequate: Construction, Planning & Design Enhancements Phase 4; Electric Geographical Information System 2018 Enhancements; Engineering Project Lifecycle; and (d) Transportation and Substation Integration Phase 3; and the DER Management System project.

134. The Settlement Agreement between Applicants and SBUA addressing issues raised by SBUA provide that if the terms are adopted with no modifications, no revenue requirement adjustments to the GRC applications will be necessary as a result of the settlement.

135. The Settlement Agreement does not discuss the revenue impacts of the various commitments that aim to better address the needs of small businesses and provides no assurance that funding for other needs will not be diverted to meet these commitments or whether shareholder funds will be used to cover any funding shortfalls.

136. The Settlement Agreement does little to resolve the many issues being litigated in the proceedings.

137. CUE's proposal for hiring more residential technicians to perform adequate CS- Field Operations work is based entirely on the personal experience of its witness as a customer and does not provide evidence that customers are experiencing delays in service such as surveys or other supporting data.

138. CUE's proposal for hiring more residential technicians is not supported by the evidence.

139. SED investigated SoCalGas' soft close practice leaving the gas on in premises in-between occupants and found that the practice does not present unreasonable risks to customers or the public.

140. The funding level for CS-F Operations should not be below 2016 recorded costs to ensure that SoCalGas has the necessary funding to provide adequate levels of customer service.

141. The underspending for the CS-F MSA Inspection Program was because SoCalGas was unable to complete all planned remediation work orders due to access issues which resulted in a backlog of approximately \$2.7 million which SoCalGas intends to complete.

142. SoCalGas bears the burden of complying with the 36-hour reconnection mandate.

143. As discussed in the CS-F and CS-MR section, SoCalGas' proposed O&M and capital forecasts for CS-F and CS-MR should be approved except for the additional funding for CS-F Operations and an adjustment to Shared O&M costs based on a different forecast methodology that was applied.

144. As discussed in the CS-F and CS-MR section, SDG&E's proposed O&M and capital forecasts for CS-F and CS-MR are reasonable.

145. D.14-12-078 authorizing implementation of the Opt-Out program was issued in December 2014 and costs associated with the program were not included in the TY2016 GRC.

146. The SMOBA balances as of December 31, 2018 for electric and gas are reasonable and supported by the evidence.

147. SoCalGas presented survey evidence that callers rate their hold times as reasonable.

148. As discussed in the CS-OO section, SoCalGas' O&M and capital forecasts for CS-OO are reasonable subject to ORA's recommended reduction for CCC Support concerning two FTEs that are not justified.

149. The request to recover balances under the EDRMA and to thereafter close the account is reasonable.

150. A 10-year rolling average of historical uncollectible rates starting from 2007 to 2016 with adjustments to occur annually by advice letter is reasonable.

151. As discussed in the CS-OO section, SDG&E's O&M and capital forecasts are reasonable subject to TURN's recommended reductions in Billing concerning additional FTEs and an adjustment to Remittance Processing.

152. The request to recover balances under the RDMA and to thereafter close the account is reasonable.

153. Informal complaints filed with CAB do not only involve issues relating to CS-OO.

154. It is improper to base SDG&E's CCC funding levels in the next GRC on the number of customer complaints filed with CAB although improving customer service to reduce the number of complaints and adequately resolving complaints within reasonable timeframes should be part of SDG&E's goals.

155. Closure of the Oceanside branch is involuntary due to the termination of the lease agreement with UPS where the branch was located.

156. Customers that utilized the Oceanside branch have managed to find alternatives for payment and other needs and no complaints have been received regarding the closure.

157. SDG&E presented testimony showing 96 percent of transactions in branch offices are payment transactions which can be serviced by APLs but this information is for all branch offices and not specifically with regards to the Downtown branch.

158. There is no input from customers of the Downtown branch concerning the types of transactions at the Downtown branch and whether these can be serviced by other means.

159. The survey questions by SDG&E about billing preference are geared towards those who already pay online and there are no questions relating to whether customers prefer paper or online billing.

160. SDG&E's existing branch office kiosks are inoperable as their useful life of 12 years has already passed.

161. Kiosks make payments easier and provide more options for customers that conduct transactions at branch offices and the new kiosks will include

enhanced functionalities such as account look-up and credit and debit card payment processing.

162. SDG&E's calculation for new branch kiosks does not consider the avoided capital costs.

163. As discussed in the CS-I section, SoCalGas' O&M and capital forecasts for CS-I are reasonable.

164. SoCalGas already conducts Spanish language qualitative research to gain a better understanding of this population segment and plans to conduct this analysis annually.

165. SBUA did not provide sufficient testimony or other evidence to support its recommendation for at least 10 additional FTEs to be trained to target the needs of the small business community.

166. As discussed in the CS-IT section, SDG&E's O&M and capital forecasts for CS-IT are reasonable subject to a reduction of \$0.5 million in RMA costs reflecting a reduction in Rate Education and Outreach activities.

167. As discussed in the CS-IT section, recovery of balances recorded in the AFVMA, EDRMA, and AB802MA and to thereafter close these accounts are reasonable. Recovery of balances under the RRMA as well as continuation of the account is reasonable.

168. As discussed in the section on CS-TPS, SoCalGas' forecasts for CS-TPS activities are reasonable.

169. SoCalGas' RD&D programs complement other R&D programs such as solicitations, host sites, and co-funding projects that complement the CEC's Natural Gas R&D program as well as projects that supplement programs by the Environmental Protection Agency and Air Resource Board.

170. SoCalGas' RD&D program is not duplicative of and supplements other R&D projects by government agencies and other groups.

171. The RD&D programs are not dependent on the CEC's funding level and utilities may pursue projects that supplement RD&D projects of other agencies and entities.

172. The comment-letters sent by SoCalGas to state and local government agencies identified by Sierra Club as constituting lobbying and were the only communications reviewed in the context of this GRC, when read as a whole and in its entirety, do not constitute efforts to block measures to replace natural gas with electric options.

173. As discussed in the section on Supply Management and Supplier Diversity, SoCalGas' and SDG&E's respective O&M forecasts are reasonable subject to the recommended reduction by NDC for Supplier Diversity.

174. SoCalGas spent 25 and 35 percent less than the authorized amounts in 2016 and 2017 respectively for Supplier Diversity and does not sufficiently justify the requested funding for TY2019.

175. Year-to-year increases in Ownership Costs have not exceeded \$3.00 million whereas SoCalGas' request represents an increase of \$25.22 million over 2016 costs.

176. Increased compliance requirements only accounts for around \$5.650 million of the increase in Ownership Costs.

177. The cost drivers for ordered and planned vehicle replacements are not unique to the TY.

178. California's policy to meet its goal of reducing GHG emissions includes widespread transportation electrification.

179. Reduction in GHG emissions that NGVs may offer does not justify SoCalGas' proposed Ownership Costs.

180. SoCalGas has been operating with less FTEs in Maintenance Operations than it is requesting.

181. Backfilling all the vacant positions in Maintenance Operations is not necessary.

182. Funding for facility improvements for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities were authorized in SoCalGas' prior GRC but the funds were utilized for other projects.

183. There are instances where funds authorized for certain projects are diverted to higher priority projects.

184. SoCalGas' request for NGV Refueling Stations reflects the projected number of vehicles based on the amount requested for Ownership Costs.

185. As discussed in the section on Real Estate, SoCalGas' forecast for Real Estate costs is reasonable.

186. As discussed in the section on Real Estate and Land Services and Facilities, SDG&E's O&M forecasts are reasonable subject to a 50 percent reduction in costs for Facilities Operations.

187. SDG&E did not reduce costs for Facilities Operations in light of the decommissioning of the RB Data Center Annex in 2017.

188. The reduction of rental costs for the RB Data Center Annex to zero reflects reduced costs for rent.

189. Blanket projects under Land Services and Facilities are necessary because some of the capital projects for this section are as yet unspecified or unplanned but later on become necessary to improve or maintain an existing asset or for safety, functionality, or other reasons.

190. SDG&E's planned projects under Land Services and Facilities captured in the historical averages are deducted from the blanket projects resulting in no double counting.

191. Several blanket projects under Land Services and Facilities are subject to computational adjustments as identified in that section.

192. The Kearney Master Plan and the Mission Critical Facility Consolidation & Expansion projects and the Ramona Construction & Operations Expansion under Business Unit Expansions are more appropriately requested and undertaken during the next GRC cycle because of insufficient information to support a comprehensive review at this time.

193. As discussed in the Environmental Services section, SoCalGas' and SDG&E's respective forecasts for Environmental Services are reasonable.

194. The only dispute with regards to the NERBA is LDAR costs and detailed information regarding the activities that will be performed in connection with LDAR are included in testimony.

195. Continuation of the two-way balancing account for NERBA is reasonable for both SoCalGas and SDG&E.

196. As discussed in the IT section, SoCalGas' and SDG&E's respective O&M and capital forecasts for IT costs are reasonable.

197. It is more appropriate in these GRCs to examine each proposed IT capital project individually rather than to base the necessity and reasonableness of each proposed project from a single fund or budget from which individual projects will be selected and funded.

198. As discussed in the section on Cybersecurity, SoCalGas' O&M and capital forecasts for Cybersecurity are reasonable.

199. As discussed in the section on Cybersecurity, SDG&E's O&M and capital forecasts for Cybersecurity are reasonable except for the Privileged Access Management project which has many overlaps with other projects.

200. Sempra formed a centralized Corporate Center that combines many shared services of SDG&E and SoCalGas and also Sempra's other businesses

201. The Corporate Center provides corporate governance, policy direction, critical control functions, and other services that are performed more effectively from a centralized operation and eliminates the need for additional staffing and other O&M costs.

202. Costs incurred by the Corporate Center for certain functions and services are fully charged out using direct assignment and allocation using the following hierarchy: Direct Assignment; Causal/Beneficial; and Multi-Factor.

203. Applicants' proposed allocation methodology is consistent with Commission decisions and Applicants' last two GRCs.

204. Parties did not raise any concerns regarding the calculation of specific allocations to SDG&E and SoCalGas.

205. As discussed in the section on Corporate Center, the forecasts for Corporate Center General Administration costs are reasonable subject to adjustments for Pension and Benefits and the acquisition of Oncor by Sempra.

206. Long-term incentive awards are stock-based and benefit shareholders rather than ratepayers although there is some benefit to ratepayers in terms of attracting and retaining employees who are experienced and high performing.

207. Post-Retirement incentives benefits shareholders as well as ratepayers.

208. Oncor comprises around 22.8 percent of the total utility assets under Sempra.

209. The Oncor transaction contain existing governance mechanisms and restrictions that limit Sempra's ability to direct the management, policies and operations of Oncor and also limit the number of Sempra representatives on Oncor's Board of Directors such that a majority of Board members are independent directors.

210. Sempra does not have direct control of Oncor and there is limited sharing of operational and financial resources between Sempra and Oncor.

211. Oncor is operated independently from Sempra unlike other business units directly controlled by Sempra.

212. Some services performed by the Corporate Center inure to the benefit of Oncor such as corporate oversight activities and other activities such as information and benefits obtained from activities by the investor relations group or external affairs and Oncor should share in the cost for these activities.

213. Most of the shared services provided by the Corporate Center are not provided directly to Oncor.

214. Only Insurance costs allocated to SDG&E and SoCalGas are included in these GRCs.

215. EMF adjusts the calculated premium based on the modifier applied.

216. While the factors affect the determination of premium to be assessed, the company's EMF score is then used to modify or adjust this determined premium to arrive at the actual premium that will be charged.

217. EMF is based on losses actual or possible insurance claims relating to the Aliso Canyon incident and the assessment of Applicants' future risk negatively impacted Applicants' EMF modifier.

218. For 2019, it is assumed that the EMF will remain at 1.25 since Applicants did not present a different figure.

219. The Aliso Canyon incident is a primary factor for Applicants' higher EMF beginning in 2016.

220. The increase of Applicants' EMF from 1.0 to 1.25 in 2016 means that the OIL premium was around 20 percent higher because of the higher EMF.

221. The Aliso Canyon incident may have a reduced impact in 2019 compared to 2016 and that other factors may affect the 2019 EMF.

222. Because the exact impact of the Aliso Canyon incident in the 2019 EMF cannot be specifically determined absent other evidence, it is reasonable that the impact attributed to the Aliso Canyon incident be one-half of the higher EMF resulting in a reduction of the requested amount for Excess Property insurance by 10 percent.

223. As discussed in the Insurance section, the forecast for Liability Insurance is reasonable except for D&O Insurance which is reduced by 50 percent.

224. D.13-05-010 found that D&O insurance protects Sempra's Board members and officers from catastrophic losses which is a benefit that accrues to shareholders and that 50 percent of these costs should be borne by shareholders.

225. As discussed in the Insurance section, the forecast for Surety Bonds is reasonable.

226. Market fluctuations and the recent wildfires in California make insurance costs difficult to predict. There are also many factors that affect insurance premiums and certain factors are outside of Applicants' control or are difficult to foresee.

227. The LIPBA allows Applicants to address these uncertainties in a timely manner and at the same time ensure that there is adequate insurance coverage for known risks.

228. Some of the risks that require adequate insurance coverage are atypical to other businesses and these include risks that can lead to severe damage and risks that are hard to predict.

229. The Commission can only review and consider the types of insurance and level of coverage that were presented in the GRC and it cannot ascertain the reasonableness of additional and other types of insurance that may be purchased and recorded in the LIPBA.

230. A total compensation study was conducted by Willis Towers Watson (WTW) as part of Applicants' TY2019 GRCs in compliance with Commission decisions.

231. The Compensation package for SDG&E and SoCalGas consists of base pay, short-term incentive compensation or variable pay for non-executives and executives, long-term compensation, and special recognition awards.

232. Base pay is incorporated in labor costs for the cost centers that they appear in and are addressed in those sections of the decision.

233. Executive ICP and LTIP are excluded from the forecast because these amounts are no longer recoverable from ratepayers.

234. Most of the performance metrics for the non-executive ICP provide tangible benefits to ratepayers but the financial metrics primarily benefit the utilities and their shareholders.

235. Any benefit resulting from achieving Applicants' financial goals is incidental and secondary to the primary goal of the financial metrics which is to reach a certain level of income or earnings.

236. In calculating Non-Executive ICP forecasts, SDG&E assumed increasing non-executive and union headcounts contrary to historical averages and applies inconsistent calculation methods with justification for the discrepancy.

237. The medical trend forecast prepared by WTW was prepared specifically for SoCalGas and SDG&E taking into account workforce demographics, location, and medical plan design.

238. It is more reasonable to apply Applicants' proposed medical trend forecast because it is more reflective of Applicants' medical premium costs.

239. The Nonqualified Savings Plan and Supplemental Pension Plan is generally applicable only to executives and other high-income employees. Thus, we find that these plans benefit both shareholders and ratepayers.

240. Funding for Retirement Activities and Special Events is denied because these activities have little connection to and provide no tangible benefits to ratepayers.

241. Pension benefits form part of the total compensation offered by Applicants to their employees.

242. Applicants are in compliance with the minimum annual contributions required by ERISA and the requirement that the annual contributions be no less than what is necessary to maintain an 85 percent AFTAP to ensure that their pension plans are fully funded.

243. Although in compliance with minimum requirements, Applicants' pension funding methods have resulted in deficits to Applicants' pension plans of approximately \$1,820 million for SoCalGas and \$690 million for SDG&E.

244. Applicants' proposal of increasing contributions to eliminate the pension shortfall over a period of time is reasonable.

245. As discussed in the section on Pension Benefits, Applicants' request to continue their respective two-way PBAs to record pension costs is reasonable.

246. As discussed in the PBOP section, Applicants' forecasts for PBOP are reasonable.

247. The framework to assess safety culture should continue to improve and evolve and contractors should be included in safety culture assessments and plans.

248. Job leveling should occur periodically instead of annually absent other evidence that shows otherwise.

249. Many employees have job functions such as office work that do not require them to drive a motor vehicle as part of their job functions.

250. The Interactive Driver Safety Program and Defensive Driver Training and In-Vehicle Refresher Course provides more benefits to the company.

251. In this case, SDG&E's membership in EEI provides benefits to ratepayers because of the industry-specific information, training, and databases that may be obtained as well as the sharing of best practices and information about research and studies made by experts and consultants.

252. Copies of invoices from EEI for 2016 and 2017 states that the portion of membership dues spent on activities relating to lobbying is 13 percent and these invoices are the best evidence in this proceeding to show what percentage was spent on lobbying.

253. As discussed in the A&G section, SoCalGas' and SDG&E's O&M forecasts are reasonable.

254. In this case, nominal amounts for giveaways and other materials were requested in conjunction with customer events to create awareness of customer programs and services.

255. In this case, logo items and clothing were not utilized primarily as promotional or advertising materials but were used as ways and means to enhance and maintain communication with customers and to ensure that they

have knowledge and access to available programs and services that they can avail themselves of.

256. SoCalGas and SDG&E voluntarily excluded costs for Meals and Entertainment from their proposed revenue requirements in an effort to reduce rates for the benefit of their customers.

257. As discussed in the A&G section, SoCalGas' and SDG&E's IT capital project requests are reasonable except for the Claims Analytics project because there were not enough tangible benefits provided about why the reporting capabilities within separate systems are inadequate.

258. Predicting the number of claims and associated costs is difficult especially since the number, type, and circumstances surrounding claims may vary with each claim and from period-to-period and a mechanism to track costs is appropriate.

259. A two-way TPCBA gives the Commission limited opportunity to review, assess, or determine whether the utility acted negligently or imprudently with respect to a claim and in such cases, ratepayers should not be responsible for any payments arising from such claims.

260. As discussed in the Shared Services and Shared Assets Billing, Capital Reassignment, and Business Segmentation, the forecasts for these costs are reasonable.

261. The policies and methods applied to Shared Services and Shared Assets billings are in compliance with the Affiliate Transaction Rules in D.97-12-088 and the same process has been applied in Applicants' prior GRCs.

262. The Capital Reassignment process complies with the Plant Instructions provided in CFR.

263. SDG&E's Business Segmentation and Electric Transmission allocation approaches apply methods that have been adopted by FERC and the Commission in prior GRCs.

264. The components utilized to determine rate base which were discussed in this section have been recognized by the Commission as the major components used to determine and calculate rate base through the RO model in prior GRCs.

265. As discussed in the section on Rate Base, SoCalGas' and SDG&E's rate base components are reasonable.

266. Estimating AFUDC as applied to construction work in progress is a practice that has been generally accepted and applied by the Commission in previous GRCs.

267. Long-term service equipment and equipment that will not be used until 2019 should not be subject to escalation.

268. Historical data shows that customer advances for construction have been increasing each year and this is likely to continue within this GRC cycle.

269. Gas Fuel in Storage is always maintained to ensure that key sections of pipeline network constantly have adequate pressure to maintain smooth operations and this amount of gas is treated as part of rate base.

270. The Oceanside Substation Land and Ocean Ranch Substation Land are now part of construction projects and are no longer considered as Land Held for Future Use.

271. Construction relating to the Oceanside Substation and Ocean Ranch Substation have been delayed but completion dates are still within the periods for which the assets will be placed in service for this GRC cycle.

272. Generally, tangible assets such as plant, property, and equipment are depreciated while intangible assets such as software and land rights and rights-

of-way are amortized. The cumulative depreciation and amortization costs are respectively reflected in the depreciation and amortization reserves.

273. SoCalGas and SDG&E propose changes to the current depreciation parameters and apply the new parameters to the depreciation study that they used to develop their respective forecasts.

274. Increasing the Average Service Life (ASL) of assets decreases the annual depreciation expense accrual in the sense that costs are stretched out over a longer period of time but this also increases depreciation expense because the longer end-of-life results in less salvage value and higher labor costs which results in increased cost of removal.

275. The proposed changes in depreciation parameters results in an increase of approximately \$6.5 million for SoCalGas and \$25.865 million for SDG&E.

276. SoCalGas and SDG&E do not provide sufficient explanation why the current depreciation parameters are deficient and need to be changed or that the proposed changes to the current depreciation parameters are superior.

277. SDG&E's authorized ASL for Electric Vehicle Supply Equipment Account (E398.20) should be 10 years instead of five.

278. The decommissioning cost estimate for SDG&E's large-scale electric production facilities should be reduced from \$19.515 million to \$16.504 million.

279. The ASL of Desert Star should be reduced by 3.17 years based on a correction of the lease and decommissioning schedule as stated in the lease contract for Desert Star.

280. The TCJA eliminated the bonus depreciation rules that were extended by the Path Act.

281. It is reasonable to update SoCalGas' and SDG&E's respective payroll tax forecasts using data from the SSA's 2018 publication rather than continuing to rely on data contained in the 2017 Report.

282. The TY2019 forecasts of SoCalGas and SDG&E apply the new federal corporate tax rate.

283. The reduction of the corporate tax rate under the TCJA created excess ADIT that should be returned to ratepayers. ADIT was formerly calculated based on a payment of deferred income taxes at the former rate of 35 percent but due to the reduction in the tax rate to 21 percent, the amount of ADIT needed to pay the deferred tax is also reduced.

284. There are two types of excess ADIT, excess deferred taxes on plant-based assets that are subject to the IRS normalization rules, also known as protected assets, and excess deferred taxes on plant-based assets that are not subject to the IRS normalization rules otherwise known as unprotected assets.

285. The IRS requires using the ARAM method to return excess ADIT for protected assets but does not prescribe a specific method to return excess ADIT for unprotected assets.

286. The IRS does not provide sufficient ARAM guidance concerning removal costs but excluding costs of removal has the effect of delaying the refund to ratepayers as compared to not applying this adjustment.

287. For excess ADIT from unprotected assets, it is reasonable that these be returned beginning in 2019 but amortized over a six-year period to allow the Commission to review and authorize any necessary adjustments resulting from further guidelines from the IRS.

288. SoCalGas' and SDG&E's TMA's should be maintained in this GRC cycle and its purpose should not be changed.

289. The TMA is not meant as a true-up mechanism between actual and forecast tax expenses that are not caused by changes in tax law, tax accounting methods, tax procedures, and tax policy.

290. Determining the dollar amount impact of the TCJA to the 2018 revenue requirement is outside the scope of these TY2019 GRCs.

291. A strict interpretation of SP U-16 should be applied in order to avoid double-counting of funds and only required minimum bank deposits should be included in the cash requirement.

292. Regarding customer deposits, SP U-16 excludes from working cash interest bearing accounts such as customer deposits.

293. As discussed in the section on Working Cash, it is more appropriate to apply some form of interest to GHG asset and liability balances similar to interest being applied to NERBA account balances rather than to include the GHG asset and liability balances to working cash and therefore part of ratebase.

294. The return on investment for funds used for essentially the same purpose, which is to purchase compliance instruments, should not differ drastically depending on whether the compliance instruments were used to offset actual omissions or are held for future use.

295. Regarding FIT and CCFT, SoCalGas and SDG&E use 2016 actual data to project TY2019 results and have shown that they receive relatively frequent refunds and are able to replicate the 2016 results in 2019.

296. SDG&E receives proceeds for auctioning its GHG allowances through the California Climate Credit and should include these proceeds in its revenue lag calculation.

297. As discussed in the section on Customer Forecasts, SoCalGas' and SDG&E's methodology utilizing information from Global Insight's regional forecast are reasonable.

298. As discussed in the section on Cost Escalation, SoCalGas' and SDG&E's escalation cost indices are reasonable.

299. As discussed in the section on Miscellaneous Revenues, SoCalGas' and SDG&E's forecasts are reasonable except for the additional amount added to SoCalGas' forecast for denial of its request to eliminate the Service Establishment Charge.

300. As discussed in the Regulatory Accounts section, many of the proposals listed in that section were reviewed, discussed, and addressed in various other sections of the decision as part of the discussion of other topics that the regulatory account addresses.

301. Recovery for TIMP and DIMP costs are currently subject to a mechanism where SoCalGas must file a Tier 3 advice letter for undercollections up to 35 percent and an application for undercollections above 35 percent of its authorized O&M and capital expenses including the capital compounding.

302. The current recovery method for TIMP, DIMP, and SIMP results in a compounding effect because capital costs are balanced over the life of the asset and not on a year-to-year basis.

303. Applicants' RO model is widely accepted by parties as being able to adequately calculate the revenue requirements for SDG&E and SoCalGas and is the same RO model used and adopted during the TY2016 GRC cycle.

304. The main factors affecting projected increases in costs anticipated during the PTYs are dissimilar with respect to O&M and capital additions.

305. The PTY mechanism for capital additions should reflect projected capital additions rather than just escalation.

306. The forecast for O&M costs is a forecast of the average increase in costs; some categories of costs are higher than average and some costs fall below the average.

307. Global Insight escalation rates are specific to the utility industry and reflect SDG&E's and SoCalGas' inflationary cost increases, and the two utilities' methodologies using Global Insight escalators are not opposed by any intervenors.

308. As discussed in the PTY section, it is reasonable to adjust rate base and associated revenue requirements during the PTYs to reflect the impact of capital additions.

309. Applicants' proposal to escalate capital additions by major plant category for each year to PTY dollars based on Global Insight indices is reasonable.

310. Continuation of the Z-Factor is reasonable.

311. A Z-Factor event is just as likely to occur during the TY as it does during the attrition years.

312. Applying the 2019 ARAM calculation to the attrition years is reasonable because, given the large number of plant-related assets, it is overly complicated to calculate ARAM on an asset-by-asset basis for the PTYs.

313. As discussed in the section on Mobilehome Park Utility Upgrade Program, SoCalGas' and SDG&E's proposed costs in that section are reasonable.

314. As discussed in the section on Accessibility Issues, the Joint Accessibility Program between Applicants and CforAT is reasonable.

Conclusions of Law

1. Any outstanding motions or requests or requests that have not been addressed in this decision or elsewhere are denied.
2. All of the oral and written rulings that the assigned ALJ has issued in this proceeding are affirmed.
3. The Commission's guidance regarding RAMP was limited at the time Applicants submitted their GRC applications.
4. We expect RAMP integration in future GRC filings to provide better information on what spending is proposed to mitigate risks and how past spending has reduced risk per dollar spent.
5. Because of the timing that statutory changes became effective, the decision should disallow cost centers that are composed entirely of officer salaries, bonuses, and benefits and should direct Applicants to track officer salaries, bonuses, and benefits in cost centers that are embedded with other costs in their respective OCMA's.
6. The OCMA balances should be trued-up in Applicants' respective year-end adjustment filings for 2019 and the amounts refunded to ratepayers.
7. Officer salaries, bonuses, and benefits should be excluded from the revenue requirements for PTYs 2020 and 2021.
8. No additional funds should be granted to perform any deferred work resulting from temporary re-assignment due to the Aliso Canyon gas leak incident.
9. Adopting a four-year GRC cycle should be applied uniformly to SDG&E, SoCalGas, PG&E and SCE and a decision on that issue should be deferred to R.13-11-006.

10. A historical linear trend is not an appropriate forecast methodology for Main Maintenance, Service Maintenance, and Tools, Fittings & Materials costs.

11. Recorded costs from 2014 to 2016 are more reflective of current costs for Main Maintenance, Service Maintenance, and Tools, Fittings & Materials.

12. The proposed increase in pipeline miles to be replaced proposed by CUE for the Aldyl-A Survey should be added to SoCalGas' forecast for Leak Survey.

13. The authorized amounts for Field Operations & Maintenance should reflect the adjustments discussed in section 7.1.1.6.4 of the decision.

14. Selectively updating only certain data or applying 2017 recorded costs in some instances but not in others may lead to inconsistent results because not all data that was submitted is being updated.

15. The Commission may at times rely on and utilize select base year plus 1 data but these instances should be limited to cases when use of such information is reasonable and sufficiently justified.

16. It is reasonable not to selectively update data if the sole reason for doing so is to update data without any explanation of why the updated data should be applied.

17. A one-way balancing account to record training costs discussed under Gas System Integrity is not necessary at this time.

18. Rather than directing and requiring immediate implementation, SoCalGas and SDG&E should instead be directed to submit testimony in their next GRCs concerning findings and the development of their respective plans concerning the establishment of a system-wide PSMS. Testimony must also address assessments related to resource needs and safety management gaps.

19. OSA's recommendations concerning safety culture enhancements are better addressed in SoCalGas' next RAMP filing.

20. The Click Enhancement Project and the Field Data Collection with eForm project requested by SoCalGas under Gas System Integrity should not be approved.

21. For rights-of-way maintenance, an increment representing costs that are 100 percent above the annual average is reasonable in recognition of non-routine activities as well as consideration of a general increase in mitigation activities resulting from the RAMP process.

22. For HCA mitigation costs, the highest level of spending during the last five years instead of the annual average is reasonable.

23. The \$7.162 million of O&M costs requested for the North-South project abandonment recovery should be addressed in the capital section of Gas Transmission Operations.

24. SoCalGas' O&M requests under Gas Transmission Operations should reflect adjustments to HCA mitigation costs, rights-of-way recovery and denial of the North-South project abandonment O&M costs.

25. SoCalGas' requests under Gas Transmission Capital should be approved except for the reduction in Auxiliary Equipment as discussed in that section.

26. Cost recovery for the North-South project of \$7.162 million annually for 2019 to 2021, should be denied.

27. Authorization to establish the MORWMA should be approved because costs to be tracked are difficult to predict and because renewal of the ROWs remains uncertain. Only costs incurred beginning January 1, 2019 should be tracked.

28. The costs to be recorded in the MROWBA should instead be tracked in the MROWMA to allow the Commission the opportunity to conduct a reasonableness review of the costs to be recovered.

29. Morongo-related capital expenses should be tracked in the MROWMA subject to recovery in SoCalGas' next GRC, because costs are still uncertain.

30. Continued two-way balancing account treatment of the SIMPBA should be authorized to allow sufficient flexibility to address possible variances in costs and at the same time allow unspent funds to be returned to ratepayers.

31. Reasonableness review of the Aliso Turbine Replacement project should be conducted in this GRC.

32. The additional \$74.6 million in project costs for the Aliso Turbine Replacement project should be approved because of the significantly expanded scope of the project following the increased environmental impacts identified in the EIR for the project.

33. Continuation of the ACMA to record additional capital-related costs in excess of \$275.5 million authorized for the Aliso Turbine Replacement project should be authorized subject to a reasonableness review of any additional costs in SoCalGas' next GRC.

34. A decision modifying the process (such as automation) of the daily imbalance trading for core customers would also apply to non-core customers and resolution of these issues were addressed in D.19-08-002 resolving issues raised in A.17-10-002.

35. SoCalGas' method and cost estimates are more appropriate for the proposed pressure test and replacement projects as compared to ORA's model.

36. More conservative contingency estimates are appropriate in this instance as the proposed Phase 2A Pressure Tests Projects and Phase 1B Replacement Projects are subject to a lesser degree of unpredictable variables relative to the earlier Phase 1A projects and because SoCalGas has more data from the earlier PSEP projects within which to make more informed and more detailed forecasts.

37. A contingency factor for PSEP projects at the lower range of the contingency cost range provided by AACE or an average of around 15 percent, is more reasonable than what SoCalGas proposes.

38. SoCalGas' total forecast for the 11 Pressure Test Projects identified in this section should be approved subject to a 10 percentage points reduction to the risk assessment component of each project.

39. Immediate corrective actions to Line 235 should be taken but SoCalGas should be required to file a Tier II Advice Letter at the conclusion of the Line 235 West Sections 1 and 2 testing or replacement with clear accounting delineations of which costs are subject to TIMP and which costs are subject to PSEP before any of the associated Line 235 costs can be placed into rates for recovery. Such PSEP costs shall not be placed into rates for recovery and such TIMP shall be made subject to refund until the Advice Letter is approved.

40. SoCalGas should be required to establish a memorandum account to record all costs related to Line 235.

41. PSEP capital-related costs not fully reflected in the TY2019 revenue requirement should be included as part of the PTYs.

42. Authorization for Line 44-1008 should be requested in SoCalGas' next GRC application.

43. SoCalGas' proposal for a three-year timeframe for completion of the Valve Replacement project should be authorized and the proposed costs should be approved subject to a 10 percentage points reduction of the risk adjustment component.

44. The approved PSEP capital projects should be subject to a 10 percentage points reduction of the risk adjustment component.

45. The procedure to request substitution of PSEP projects described in SoCalGas' testimony should be followed except that SoCalGas should file the request as a Tier 2 advice letter in order to afford the Commission sufficient opportunity to review the proposal without unnecessarily delaying the process.

46. Instead of continuing the two-way balancing treatment for PSEP, the creation of a memorandum account to track potential PSEP overrun costs should be authorized.

47. Pipeline projects under Phase 2B of SoCalGas' Implementation Plan must comply with D.11-06-017, and it is reasonable to require SoCalGas to ensure that this compliance occurs in a manner that quantifiably mitigates risk and ensures that funds spent are reasonable for ratepayers. .

48. It is prudent to consider the potential impact of Resolution E-4981 and D.19-08-014 in the analysis of the costs being included for the acquisition of Otay Mesa.

49. OMEC-related costs should be removed from the GRC revenue requirement now that the Otay Mesa acquisition will not be completed.

50. SDG&E should deduct OMEC costs, incremental work for Resource Planning, and Chamber of Commerce Dues in 2016 for Boulder City from its O&M forecast for Electric Generation.

51. A two-way balancing account for Tree Trimming should be approved.

52. Continuance of SDG&E's PBR mechanism that was in place during the prior GRC cycle for meeting target SAIDI and SAIFI values is not necessary for this GRC cycle.

53. ORA's forecast method for New Business is more reasonable and should be adopted in light of the large discrepancies between forecast and actual CUs in 2014 to 2016.

54. Under Materials, the forecast for Meters and Regulators should follow ORA's forecast for New Business.

55. SDG&E should file a Tier 1 advice letter to establish a one-way balancing account for Overhead Pools within 60 days from the effective date of this decision.

56. In connection with the AES Storage project in section 21 of the decision, SDG&E should submit a report in its next GRC detailing the total actual project cost, including the specific cost of procuring the energy storage systems, and summarizing the specific benefits realized to ratepayers from the project.

57. The Settlement Agreement between Applicants and SBUA is not reasonable in light of the record as a whole and the Joint Motion for Adoption of Settlement Agreement should be denied.

58. SoCalGas should apply the additional \$0.859 million to its forecast to its new program of restoring service to customers that have been disconnected for non-payment within 36 hours of disconnection to ensure that SoCalGas has sufficient funding for this program.

59. SoCalGas should demonstrate that it is complying with the Executive Director's direction regarding the 36-hour reconnection period without underfunding or understaffing other work, such as responding to customer service requests or addressing customer safety concerns.

60. SoCalGas should provide information about customer wait times for safety concerns and service requests and must show that those wait times are reasonable for customers requesting assistance in English as well as in other languages.

61. The true-up balances recorded in the SMOBA should be addressed in this GRC. The request to recover SMOBA balances as of December 31, 2018 for electric and gas and to thereafter close the account should be granted.

62. The request to close the Oceanside branch should be granted but closure of the Downtown branch should be denied at this time.

63. SDG&E's request to default customers to paperless billing should be denied at this time.

64. SDG&E's Branch Office Kiosk Replacement project under CS-OO should be approved with a budget that does not exceed the cost using existing kiosks.

65. The authorized funding branch kiosks should not result in any net increase over the use of existing kiosks resulting in \$1.106 in 2018 that should be approved for new branch kiosks.

66. Approval of the funding for the RD&D program should be subject to a one-way balancing account treatment and unspent funds should be returned to ratepayers at the end of each GRC cycle.

67. SoCalGas should host an annual workshop during the second quarters of 2020 and 2021 under supervision of the Commission's Energy Division and present the result of the previous year's RD&D program and obtain input regarding its intended spending for the following calendar year.

68. Costs related to multi-year project and single-year projects under the current RD&D program will continue to be funded consistent with the TY2016 protocols until the planned completion of those projects.

69. ORA's recommendation to use 2017 actual vehicle ownership costs for SoCalGas' and SDG&E's respective Ownership Costs should be adopted subject to TURN's recommendation to add costs relating to ATCM compliance replacements.

70. 50 percent of the requested adjustment to backfill vacant FTEs for Maintenance Operations should be approved as this level of funding will enable SoCalGas to perform the increased work it has identified but takes into account the number of FTEs during recent years.

71. The requested funding for facility improvements for the Compton, Chatsworth, Anaheim, and Pico Rivera facilities for 2018 and 2019 should be approved. The amounts requested for 2017 should be denied because no amounts were actually spent.

72. In light of the disapproval of a significant portion of SoCalGas' requested amounts under Ownership Costs, the amounts for NGV refueling stations should also be reduced.

73. Because of the reduction in authorized amounts for SoCalGas' NGV refueling stations capital project by around 60 percent, ORA's recommendation to likewise reduce the O&M amount pertaining to costs for NGV refueling stations by the same percentage should be approved.

74. SDG&E's Maintenance Costs associated with incremental vehicles should be denied in light of the denial of most of the funding for incremental vehicles under Ownership Costs.

75. TURN's recommendation of reducing costs for Facilities Operations corresponding to the RB Data Center Annex by 50 percent should be adopted.

76. Costs for Long-Term Incentives should be disallowed while costs for Post-Retirement benefits should be reduced to 50 percent because it benefits both shareholders and ratepayers.

77. Because Corporate Center activities are not performed directly for Oncor, it should only be part of costs involving the multi-factor allocation method.

78. The calculation which added the \$9.566 billion Oncor acquisition price to the total Gross Plant Assets and Investments of Sempra and all its business units should be used as the asset total.

79. Applying the multi-factor method to the asset total results in a \$2.4 million reduction to Applicants' requested allocation costs; the allocation costs should be reduced to \$2.219 million because of the reduced amounts approved for Pension and Benefits.

80. There should be some mechanism within which to review additional insurance expenditure that was not requested in these GRCs.

81. Authority to establish the LIPBA as a two-way balancing account should be granted in this decision.

82. Applicants should be required to file a tier 2 advice letter when they seek recovery of costs for additional liability insurance coverage that were not requested in these GRCs.

83. 10 percent of the ICP, or the amount representing the financial metrics, should be disallowed.

84. It is reasonable to apply constant 2016 non-executive and union employee headcounts and apply the same methodology in calculating both non-executive and union employee ICP costs.

85. The Nonqualified Savings Plan and Supplemental Pension Plan benefit both shareholders and ratepayers equally so only 50 percent of the requested costs should be allowed.

86. It is more appropriate to spread out the costs of funding the PBO shortfall over a longer period of time than Applicants propose.

87. It is more appropriate to use the average age of retirement instead of 65 as the basis of time for which the PBO shortfall should be funded and

contributions should be increased such that the pensions become fully funded within 14 years using the average age SoCalGas and SDG&E retirement plan participants are expected to retire.

88. SoCalGas should be required to submit a report in its next GRC application that details the studies conducted, findings made, and steps taken regarding a multi-method framework to assess safety culture and including contractors in safety culture assessments.

89. The incremental cost for job leveling should be treated as a non-recurring cost and spread the cost over the three years included in the GRC cycle.

90. Ratepayers should not be held responsible for costs to mitigate driving incidents where driving is not part of an employee's work in providing safe and reliable natural gas and electric services to customers.

91. Since it is not clear what percentage of employees are required to drive as part of their work and because some residual benefits accrue to ratepayers, SoCalGas should recover 50 percent of the costs for the Interactive Driver Safety Program and Defensive Driver Training and In-Vehicle Refresher Course.

92. SDG&E's forecast for EEI dues should be accepted.

93. It is reasonable to authorize the creation of a TPCMA in lieu of the TPCBA and SDG&E should be allowed to seek recovery of reasonable costs in excess of the authorized amount for third-party claims through the advice letter process by filing a Tier 2 advice letter to request recovery of such amounts.

94. It is reasonable to apply the authorized rate of return for AFUDC as applied to construction work in progress for 2017, 2018, and 2019.

95. The Oceanside Substation Land and Ocean Ranch Substation Land should be included in rate base.

96. SoCalGas' and SDG&E's requests to change their current depreciation parameters should be rejected resulting in a reduction of \$6.5 million and \$25.865 million to their respective depreciation expense forecasts. SDG&E should further reduce its depreciation expense forecast by \$3.011 million representing the reduction to its decommissioning cost estimate and also calculate the impact of the reduced ASLs for Electric Vehicle Supply Equipment and Desert Star.

97. Absent clear guidance from the IRS, we find that removal costs should be allowed so as not to delay the refund to ratepayers.

98. SoCalGas and SDG&E should track the revenue requirement difference between including and excluding cost of removal from the ARAM calculation in the event that the IRS issues a ruling or releases further guidance stating that it would be a normalization violation to include cost of removal in the ARAM calculation, and SoCalGas and SDG&E should then seek recovery of any difference in costs by filing a Tier 2 advice letter seeking appropriate adjustment to its revenue requirement.

99. The TMA should continue to track only differences resulting from (a) net revenue changes, (b) mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and (c) elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes as provided in D.16-06-054. SoCalGas and SDG&E may file separate Tier 1 advice letters within 45 days from the effective date of this decision to implement any necessary changes to their respective TMAs consistent with this decision.

100. SoCalGas and SDG&E should be required to file separate Tier 2 advice letters within 45 days from the effective date of this decision, to implement

adjustments to their respective revenue requirements for 2018 in order to reflect the 2018 tax savings from the TCJA in rates.

101. The short-term debt interest rate should be applied to GHG asset and liability balances similar to what is mandated for fuel and commodity inventories.

102. Depreciation and deferred income taxes are allowed to be included in working cash under the principles set forth in SP U-16.

103. The dispositions regarding the various regulatory accounts in section 43 of the decision should be adopted.

104. It is reasonable to allow SDG&E and SoCalGas to change the method of calculating undercollections relating to TIMP, DIMP, and SIMP recovery by allowing the undercollection percentage to be calculated by applying it against the total authorized O&M and capital expenses, including the capital compounding.

105. As discussed in the Summary of Earnings section, the proposed RO model should be adopted.

106. It reasonable to apply different PTY mechanisms for O&M and for capital additions.

107. Applicants did not fully justify why medical costs should be treated differently from other O&M costs and the same PTY mechanism applied to O&M costs should be applied to medical costs.

108. For these GRCs, labor and non-labor costs should be based on the IHS Markit Global Insight forecast.

109. PTY computations for capital additions should be based on a seven-year average using recorded and forecasted capital additions for 2013 to 2019.

110. SDG&E is specifically required by AB 1054 to exclude \$215 million of approved fire risk mitigation capital expenditures from equity rate base.

111. The Z-Factor should apply to the TY as well as the PTYs.

112. SDG&E and SoCalGas should continue to update their PTY revenue requirements by filing Tier 1 advice letters two months prior to the beginning of each attrition year.

O R D E R

IT IS ORDERED that:

1. Application 17-10-007 is granted to the extent set forth in this Decision. San Diego Gas & Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2019 test year base revenue requirement set forth in Attachment B, effective January 1, 2019.

2. Application 17-10-008 is granted to the extent set forth in this Decision. Southern California Gas Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2019 test year base revenue requirement set forth in Attachment B, effective January 1, 2019.

3. Within 30 days from the effective date of this Order, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) shall each shall file respective Tier 1 Advice Letters with revised tariff sheets to implement the revenue requirements authorized in Ordering Paragraphs 1 and 2.

- a. The revised tariff sheets shall become effective on January 1, 2019 subject to a finding of compliance by the Commission's Energy Division, and compliance with General Order 96-B.
- b. The balances recorded in SoCalGas' and SDG&E's respective General Rate Case Revenue Requirement Memorandum Accounts from January 1, 2019 until the effective date of the new tariffs required by this Ordering Paragraph shall be

amortized in rates thirty days after the effective date of this decision through December 31, 2021.

4. Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company are each authorized to implement a Post-Test Year Ratemaking mechanism for 2020 and 2021, as follows:

- a. Labor and non-labor costs as well as medical costs be based on the IHS Markit Global Insight forecast;
- b. Capital investments be based on an escalated seven-year average of capital additions and for SoCalGas, a forecast of Pipeline Safety Enhancement Plan capital additions beyond Test Year 2019; and
- c. Continuation of their currently authorized Z-Factor mechanisms.

5. Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) shall update their Post-Test Year revenue requirements by filing respective Tier 1 advice letters two months prior to the beginning of each attrition year. To adjust the revenue requirement for 2020, SoCalGas and SDG&E shall each file a Tier 1 Advice Letter with the Commission's Energy Division on or before November 1, 2019 with the update to the Test Year 2019 revenue requirement to be effective on January 1, 2020. Similarly, Tier 1 Advice Letters are to be filed on November 1, 2020 to adjust the revenue requirement for 2021 beginning on January 1, 2021.

6. Beginning in Post-Test Year (PTY) 2020, San Diego Gas & Electric Company (SDG&E) shall adjust its PTY revenue requirements to reflect the equity rate base exclusion required by Assembly Bill 1054. SDG&E shall file a Tier 3 Advice Letter concurrent with its year-end adjustment filing for 2019, providing a detailed explanation and showing of the revenue requirement

impact of the Public Utilities Code section 8386.3(e) equity rate base exclusion when it makes its annual PTY revenue requirement implementation filings.

7. Southern California Gas Company's (SoCalGas) regulatory account proposals are authorized except as follows:

- a. Fire Hazard Prevention Memorandum Account (FHPMA). Recovery of balances under the FHPMA is authorized subject to a reduction of \$0.1 million representing interest as SoCalGas should have sought recovery of this balance at an earlier time;
- b. Discontinuation of Service Establishment Charges (SEC). SoCalGas' request to eliminate the SEC is denied;
- c. Pipeline Safety Enhancement Plan Balancing Account (PSEPBA). Authority to establish the PSEPBA is denied. SoCalGas is instead authorized to establish a Pipeline Safety Enhancement Plan (PSEP) memorandum account to track PSEP costs and request recovery of amounts in excess of the amounts authorized in this decision;
- d. Morongo Rights-of-Way Balancing Account (MROWBA). Authority to establish the MROWBA is denied. Costs proposed to be recorded in the MROWBA must instead be tracked in the Morongo Rights-of-Way Memorandum Account;
- e. Liability Insurance Premium Balancing Account (LIPBA). SoCalGas shall file a Tier 2 advice letter when it seeks recovery of costs for additional liability insurance coverage that were not requested in this General Rate Case; and
- f. Southern California Gas Company shall be allowed to include capital compounding calculations to its capital expenses for its Transmission Integrity Management Program, Distribution Management Integrity Program and Storage Integrity Management Program Balancing Accounts.

8. San Diego Gas & Electric Company's (SDG&E) regulatory account proposals are authorized except as follows:

- a. Fire Hazard Prevention Memorandum Account (FHPMA). Recovery of balances under the FHPMA is authorized subject to a reduction of \$44,712 representing interest as SDG&E should have sought recovery of this balance at an earlier time;
- b. Tree Trimming Balancing Account (TTBA). Modification of the TTBA from a one-way to a two-way balancing account is authorized. However, SDG&E is required to file a Tier 3 Advice Letter for recovery of undercollections up to 35 percent and an application for undercollections above 35 percent;
- c. Liability Insurance Premium Balancing Account (LIPBA). SDG&E shall file a Tier 2 advice letter when it seeks recovery of costs for additional liability insurance coverage that were not requested in this General Rate Case; and
- d. San Diego Gas & Electric Company shall be allowed to include capital compounding calculations to its capital expenses for its Transmission Integrity Management Program and Distribution Management Integrity Program Balancing Accounts.

9. Southern California Gas Company and San Diego Gas & Electric Company shall comply with Resolution E-4963 and track in their respective Officer Compensation Memorandum Accounts officer compensation and benefits that are still included in their respective Test Year 2019 revenue requirements.

10. Southern California Gas Company and San Diego Gas & Electric Company shall track officer salaries, bonuses, and benefits in cost centers that are embedded with other costs in their respective Officer Compensation Memorandum Accounts.

11. The Officer Compensation Memorandum Account balances shall be trued-up in Southern California Gas Company's and San Diego Gas & Electric

Company's respective year-end adjustment filings for 2019 and the amounts refunded to ratepayers.

12. Officer salaries, bonuses, and benefits shall be excluded from the revenue requirements for Post-Test Years 2020 and 2021.

13. Southern California Gas Company (SoCalGas) shall file a Tier 2 Advice Letter at the conclusion of Line 235 West Sections 1 and 2 testing or replacement with clear accounting delineations of which costs are subject to the Transmission Integrity Management Program (TIMP) and which costs are subject to the Pipeline Safety Enhancement Plan (PSEP) before any associated Line 235 PSEP pressure testing costs can be placed into rates for recovery. Such PSEP costs shall not be placed into rates for recovery and such TIMP costs shall be made subject to refund until the Advice Letter is approved. The Line 235 costs subject to this accounting requirement include costs SoCalGas is incurring for the additional permits, crews, environmental monitoring, and all other costs associated with investigating and repairing the ongoing leaks on Line 235. Line 235 repair costs in TIMP will be reviewed in a future general rate case.

14. Southern California Gas Company shall establish a memorandum account within 20 days from the effective date of this decision and at that time shall begin to record all costs related to Line 235 West Sections 1 and 2 (i.e., capital costs including rate of return, operations and maintenance costs, repair and replacement costs, or any other costs related to the line).

15. To ensure that pipelines under Phase 2b comply with D.11-06-017, SoCalGas shall file a re-testing implementation plan as part of SoCalGas's 2019 RAMP filing, and the plan shall specifically include the following:

- a. Identification of all in-service natural gas transmission pipelines (by location and including linear feet and the pipelines')

- categorization in Class locations 1-4) that were tested under the ASA Code and for which test records exist;
- b. Identification of the subset of the above qualifying pipelines for which SoCalGas recommends and does not recommend a re-test, and a statement explaining why a re-test is proposed or not proposed;
 - c. Presentation of the pre-1970 ASA Code test records for the pipelines proposed to be re-tested, and direct comparison of the test elements shown in the records to the test elements set out in 49 CFR 192.619;
 - d. An evaluation by an independent engineer that SoCalGas's proposed determination of which pipelines to re-test or not to re-test is a reasonable engineering judgement;
 - e. The forecast costs of re-testing; and
 - f. Consistent with the RAMP framework, a complete discussion of the risk-spend efficiency of the dollars proposed to be spent.

16. Southern California Gas Company shall file a Tier 2 Advice Letter to request project substitution of an approved Pipeline Safety Enhancement Plan with another project. The advice letter will contain the name and scope of the delayed project, the circumstances that led to the substitution, and identification of the substituted project as well as the scope and estimated costs to complete the substituted project.

17. San Diego Gas & Electric Company shall file a Tier 1 Advice Letter to establish a one-way balancing account for Overhead Pools within 60 days from the effective date of this decision.

18. Southern California Gas Company and San Diego Gas & Electric Company shall update their respective uncollectible expense rate for Post-Test Years 2020 and 2021 by filing respective annual Tier 1 Advice Letters to the Commission's Energy Division.

19. Within 180 days from the effective date of this decision, Southern California Gas Company (SoCalGas) shall file a Tier 3 Advice Letter certifying that it is dedicating the additional funding of \$0.859 million for Customer Services Field & Meter Reading to improving its reconnection rates and explain, with specificity, what steps it is taking to ensure that reconnection times stay within that 36-hour period. The Advice Letter must demonstrate that SoCalGas is complying with the 36-hour reconnection period without underfunding or understaffing other work and shall also provide information about customer wait times for safety concerns and service requests and show that those wait times are reasonable for customers requesting assistance in English as well as in other languages.

20. San Diego Gas & Electric Company shall file a Tier 2 Advice Letter to request recovery of reasonable costs in excess of the authorized amount for third-party claims.

21. Southern California Gas Company and San Diego Gas & Electric Company shall file separate Tier 2 Advice Letters to seek appropriate adjustment to its revenue requirement for any difference between including and excluding cost of removal from the Average Rate Assumption Method (ARAM) calculation in the event that the Internal Revenue Service issues formal guidance contrary to the approach this decision takes in disallowing exclusion of costs of removal from the ARAM calculation.

22. Southern California Gas Company and San Diego Gas & Electric Company must file separate Tier 2 Advice Letters within 45 days from the effective date of this decision, to implement adjustments to their respective revenue requirements for 2018 in order to reflect the 2018 tax savings from the Tax Cuts and Jobs Act in rates.

23. San Diego Gas & Electric Company shall remove costs for two projects concerning the Palomar plant that should have been disallowed in 2012 but were still included in the revenue requirement beginning in 2016.

24. San Diego Gas & Electric Company is authorized to close the Oceanside branch office but the request to close the Downtown branch office is denied at this time.

25. In its next General Rate Case filing, Southern California Gas Company shall include testimony confirming any costs associated with Morongo Rights-of-Way negotiations and resolution of negotiations if an agreement is reached.

26. Southern California Gas Company shall include a Safety Management Systems proposal in its next General Rate Case application.

27. In its next General Rate Case (GRC), Southern California Gas Company shall include an outlook of its long-term assessment and replacement plan for Aldyl-A pipes and bare steel pipes without cathodic protection, in addition to assessment and replacement activities planned for the next GRC cycle.

28. San Diego Gas & Electric Company shall include an outlook of its long-term assessment and replacement plan of its Aldyl-A pipes and the Distribution Risk Evaluation and Monitoring System program pipe replacement in its next General Rate Case (GRC) in addition to the activities planned for the next GRC cycle.

29. San Diego Gas & Electric Company shall submit a report in its next General Rate Case detailing actual project costs for the Advanced Energy Storage project. The report shall include the specific costs of procuring the energy storage systems and a summary of the specific benefits realized by ratepayers.

30. Southern California Gas Company (SoCalGas) shall host an annual workshop during the second quarter of 2020 and 2021 under supervision of the Commission's Energy Division. At these workshops, SoCalGas shall present the result of the previous year's Research, Development, and Demonstration (RD&D) program and obtain input regarding its intended spending for the following calendar year. Prior to the workshop, SoCalGas shall:

- a. Submit a report to Energy Division staff describing prior years' RD&D program including a summary of ongoing and completed projects; funds expended, funding recipients, and leveraged funding; and an explanation of the process used for selecting RD&D project areas as well as the structure of SoCalGas' RD&D portfolio;
- b. Provide Energy Division staff with the workshop presentation materials as well as documentation of stakeholders consulted in the development of RD&D projects, both at least one week before the workshop; and
- c. Engage relevant stakeholders to encourage their attendance at the workshop, such as the California Energy Commission, Gas Technology Institute, the U.S. Department of Energy, and other organizations engaged in gas research and development.

SoCalGas must also present its budget broken down by research projects, request for proposals, and funding amounts. Other specific details concerning the workshops must be coordinated with the Commission's Energy Division staff.

31. Southern California Gas Company and San Diego Gas & Electric Company shall provide testimony in their next General Rate Cases on the current funding levels and outstanding balance of their Pension Benefit Obligations so the Commission can assess whether any modifications are needed.

32. In their next respective General Rate Case applications, Southern California Gas Company and San Diego Gas & Electric Company must include a report in the form of testimony that details the studies conducted, findings made, and steps taken regarding a multi-method framework to assess safety culture and including contractors in safety culture assessments.

33. If a decision adopting a four-year General Rate Case cycle is made in Rulemaking 13-11-006, Southern California Gas Company and San Diego Gas & Electric Company shall file a petition for modification of this decision to request review and implementation of Southern California Gas Company's and San Diego Gas & Electric Company's post-test year proposals for 2022.

34. Applications 17-10-007 and 17-10-008 are closed.

This decision is effective today.

Dated September 26, 2019, at San Francisco, California.

MARYBEL BATJER

President

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

GENEVIEVE SHIROMA

Commissioners