Agenda ID #14308 (Rev. ~~2~~3)
Ratesetting
11/5/2015 Item 32

Decision **PROPOSED DECISION OF ALJ DUDNEY** (Mailed 9/18/2015)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Authority to, among other things, Increase its Authorized Revenues for Electric Service in 2015, and to reflect that increase in Rates.	Application 13-11-003 (Filed November 12, 2013)

DECISION ON TEST YEAR 2015 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

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APPENDIX A - List of Acronyms
APPENDIX B – Timeline of Events Relevant to Disputed Tax Issues

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APPENDIX C – Results of Operations 2015
APPENDIX D – Post-Test Year Results

DECISION ON TEST YEAR 2015 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

Summary

This decision approves a test year revenue requirement of $~~5,189~~5,182 million (for ~~a 7.88~~an 8.00% decrease) for Southern California Edison Company (SCE) pursuant to its 2015 General Rate Case Application 13-11-003, as summarized in Appendix C of this decision. The adopted revenue requirement reflects our careful assessment of SCE's 2015 test year base revenue requirements necessary to provide safe and reliable service. Appendix C contains the results of operations supporting tables for SCE, which incorporates the forecasted costs we find to be reasonable, and which are adopted in today's decision. The adopted 2015 revenue requirements shall become effective upon filing of tariffs pursuant to the directives of this decision.

This decision also authorizes attrition rate adjustments of $209 million (~~4.03~~4.04%) for 2016 and an additional $272 million (~~5.03~~5.04%) for 2017 as set forth in Appendix D of this decision to provide funds necessary for SCE to continue to provide safe and reliable service to customers beyond the test year, while offering a reasonable opportunity to earn the rate of return previously found reasonable by the Commission. The cumulative adopted effect on rates by 2017, relative to present rates, is a ~~0.66~~0.54% increase.

The authorized amounts are less than SCE requested. SCE's final updated request for its total 2015 forecasted revenue requirement was $5,512 million, representing a 2.15% decrease relative to present rates. SCE requested attrition year increases of $236 million and $320 million for 2016 and 2017, respectively. SCE's requested cumulative increase, relative to present rates, by 2017 is 7.72%.

One significant component of SCE's request in this application is for capital expenditures. The impact of current capital expenditures on current revenue requirements is small, but the cumulative impact is powerful over time as the value of the capital assets (including rate of return and cost of removal) is repaid by ratepayers. SCE requests approximately $3.9 billion in capital expenditures during 2015 alone, of which it identifies $2.8 billion as directly related to ten primary risks (many of which are directly linked to safety and reliability).[1] We approve approximately $3.4 billion of total capital expenditures, reflecting our judgement that the long-term benefits of these investments justify the costs. However, we also deny notable portions of SCE's request for expenditures that SCE has not demonstrated are just and reasonable costs of safe and reliable service.

SCE identifies several key justifications for its requested revenue requirements and capital expenditures:

- Connecting new customers and responding to customer requests, such as undergrounding;
- System reinforcements to accommodate load growth;
- Capital investments to replace aging distribution infrastructure and business systems;
- Testing and replacement (where needed) of over 1.4 million distribution poles; and
- An increase in depreciation rates to account for increases in cost of removal and other depreciation parameters.[2]

The authorized increase in revenue requirement reflects the costs forecast for test year 2015 for delivering electricity to customers, maintaining SCE's electric distribution and generation infrastructure, and providing safe and

[1] Exhibit SCE-17 at 3-8.
[2] Application 13-11-003 at 1-2.

reliable service. The revenue requirement authorized in this decision does not include commodity costs of electricity procured for customers or costs of fuel used in generating electricity, which are addressed in a separate proceeding.

1. Procedural Background

On November 12, 2013, Southern California Edison Company (SCE) filed its Test Year (TY) 2015 General Rate Case (GRC) Application (A.) 13-11-003. In support of its application, SCE provided thousands of pages of testimony and supporting work papers, and sponsored many witnesses. Protests or other responses were filed on December 16, 2013 by Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), The Greenlining Institute (Greenlining), Coalition for Affordable Streetlights (CASL), Alliance for Retail Energy Markets jointly with Direct Access Customer Coalition, and National Consumer Law Center. SCE proposed a procedural schedule based on the Commission's 1989 Rate Case Plan, as modified by numerous subsequent decisions. Other parties proposed more extended schedules. The prehearing conference in this proceeding was held on February 11, 2014.

On February 14, 2014, TURN filed a motion asking the Commission to authorize a GRC Revenue Requirement Memorandum Account (RRMA) to track the change in revenue requirement ultimately adopted in this proceeding during the period between January 1, 2015 and the date a final decision is adopted. On March 3, 2014, SCE filed a response in support of this motion. The motion was granted in the March 27, 2014 Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges (Scoping Memo).

The Scoping Memo noted a broad scope of issues for the case: "all matters raised by SCE's application, or which may be reasonably inferred from the application, are within scope of this proceeding." However, the Scoping Memo

excludes issues relating to the San Onofre Nuclear Generating Station (SONGS), to the extent practicable, as well as the Four Corners Generating Station.[3] SCE served additional testimony (Exhibit SCE-14) responding to these changes and other requirements in the Scoping Memo on April 7, 2014.

On May 15, 2014, Commission President Michael Peevey (who was the assigned Commissioner at that time) issued a Ruling Amending Scoping Memo and Ordering Supplemental Testimony Regarding Risk Management and Safety Matters (Amended Scoping Memo). This ruling directed SCE serve testimony addressing three questions relating to risk management, existing controls, and alternatives. SCE served the requested testimony (Exhibit SCE-15) on July 3, 2014. The Commission's Safety and Enforcement Division (SED) served a report in response to SCE's testimony on August 15, 2014. SED's report was later admitted into evidence (Exhibit ALJ-1).

ORA, California City-County Street Light Association (Cal-SLA), CASL, California Coalition of Utility Employees (CUE), Small Business Utility Advocates (SBUA), San Diego Gas & Electric Company (SDG&E), and TURN, served their direct testimony in August, 2014. Parties served reply and rebuttal testimony in September, 2014. Joint Minority Parties (JMP)[4] did not serve direct testimony, but did serve rebuttal. Evidentiary hearings began on September 29, 2014 and concluded on October 28, 2014.

On November 17, 2014, the parties jointly served a three-volume Joint Comparison Exhibit (Exhibits JCE-1, JCE-2, and JCE-1C). This was later updated with reorganized versions containing the same information (JCE-3 and JCE-4,

[3] Scoping Memo at 3-7.

[4] JMP is a group consisting of: National Asian American Coalition, Ecumenical Center for Black Church Studies, Jesse Miranda Center for Hispanic Leadership, Los Angeles Latino Chamber of Commerce, National Hispanic Christian Leadership Conference, and Christ Our Redeemer AME Church.

served December 15, 2014) and errata (JCE-1CA, JCE-1A, JCE-2A, JCE-3A, JCE-4A, served January 30, 2015).

On November 25, 2014, opening briefs (OBs) were filed and served by: SCE, ORA, TURN, SBUA, CUE, Cal-SLA, SDG&E, and CASL. On December 12, 2014, reply briefs (RBs) were filed and served by: SCE, ORA, TURN, CASL, CUE, and SDG&E.

SCE served update testimony on December 17, 2014 (SCE-73, SCE-73C), and later errata (SCE-73A, SCE-73CA, served January 8, 2015). Evidentiary hearings about these materials were held on January 13, 2015.

Various other exhibits were served after the update hearings in response to Administrative Law Judge (ALJ) rulings or by motion of a party. These exhibits, as well as many of those discussed above, were admitted into evidence by various email rulings. These exhibits are summarized in the following table.

Exh. #	Description	Introduced	Admitted
SCE-74	Revenue Requirement Changes	1/30/15	02/27/15
JCE-1	Joint Comparison Exhibit	11/17/14	02/27/15
JCE-1A	Joint Comparison Exhibit (Errata)	1/30/15	02/27/15
JCE-1C	Confidential Joint Comparison Exhibit	11/17/14	02/27/15
JCE-1CA	Confidential Joint Comparison Exhibit (Errata)	1/30/15	02/27/15
JCE-2	Joint Comparison Exhibit	11/17/14	02/27/15
JCE-2A	Joint Comparison Exhibit (Errata)	1/30/15	02/27/15
JCE-3	Joint Comparison Exhibit	12/15/14	02/27/15
JCE-3A	Joint Comparison Exhibit (Errata)	1/30/15	02/27/15
JCE-4	Joint Comparison Exhibit	12/15/14	02/27/15
JCE-4A	Joint Comparison Exhibit (Errata)	1/30/15	02/27/15
SCE-76	Revenue Requirement Changes	5/11/15	8/17/15
SCE-77	Supplemental Exhibit in Response to ALJ Email Ruling 05/06/15	5/22/15	8/17/15
SCE-78	Supplemental Exhibit in response to ALJ Email Ruling 07/17/15	7/24/15	8/17/15
ORA-10-WP Part	Workpapers to ORA-10, Volumes 1 (Revised)	1/16/15	02/27/15

1 R			
ORA-10-WP Part 2 R	Workpapers to ORA-10, Volumes 2 (Revised)	1/16/15	02/27/15
ORA-15-WP R	Workpapers to ORA-15 (Revised)	1/16/15	02/27/15
TURN-06 R	Report on Various Results of Operations Issues in Southern California Edison's 2015 Test Year General Rate Case – REVISIONS for The 2014 Tax Act	2/17/15	03/10/15

The proceeding was submitted on July 24, 2015.

We thank the parties to this proceeding for their participation in our testing of the online supporting documents system. We hope that this system will soon assist parties and the public to access prepared exhibits in California Public Utilities Commission (CPUC) proceedings.

2. Background on Recorded Cost Data

The record of this proceeding relies heavily on recorded spending information, particularly for the period 2008 through 2012. In particular, 2012 is referred to as the base year or last recorded year (LRY). In some areas, 2013 recorded data is also discussed. Some common forecasting techniques that rely on historical data are LRY or a five-year average (5YA), which generally refers to 2008-2012, unless otherwise noted.

Much of the recorded data in this proceeding is organized using a system of accounts established by the Federal Energy Regulatory Commission (FERC). FERC Accounts are used to record operations and maintenance (O&M) costs. Many FERC Accounts include sub-accounts, and the sub-accounts are the unit of analysis for many issues. Sub-accounts are shown as three decimal places following the account number. For example: FERC sub-account 561.170 records costs related to Grid Control Center (GCC) Operations.

3. Evidentiary Standards and the Burden of Proof

No party disputes that SCE bears the burden of proof.[5] As the applicant, SCE has the burden of affirmatively establishing the reasonableness of all aspects of its request.

SCE contends that the appropriate evidentiary standard is "preponderance of the evidence." In support of this view, SCE points to its two most recent GRCs, as well as the two most recent GRCs of Pacific Gas and Electric Company (PG&E).[6] We agree, and have analyzed the record in this proceeding according to this standard. As a general matter, with respect to individual uncontested issues in this proceeding, we find that SCE has made a prima facie just and reasonable showing, unless otherwise stated in this opinion.

4. Risk Management and Safety Matters

One of the central tasks facing the Commission in this proceeding is to balance safety and reliability risks in comparison with cost. SCE is required by law to "promote the safety, health, comfort, and convenience of its patrons, employees, and the public" while including only "just and reasonable" charges in its rates.[7] Our fundamental challenge in many disputed areas of this case is to reach an outcome consistent with these twin objectives. This is a familiar challenge that has been present in countless previous GRCs and other proceedings, even though the approach, framework, and language surrounding the issues continue to evolve.

In Decision (D.) 14-12-025, we adopted a new framework for future GRCs to "assist the utilities, interested parties and the Commission, in evaluating the

[5] See Public Utilities Code § 454. Unless otherwise noted, statutory citations refer to the Public Utilities Code.
[6] SCE OB at 20.
[7] § 451.

various proposals that the energy utilities use for assessing their safety risks, and to manage, mitigate, and minimize such risks."[8] Much of the record of this proceeding was complete before that decision was adopted, so we are not fully able to use that framework. Nevertheless, we review SCE's application with an eye toward balancing cost and risk.

For its part, SCE appears to agree with the need to balance these objectives, stating that its showing reflects what SCE's senior executives and Board of Directors believe "is the right balance between infrastructure investments, operational requirements, and moderate rate increases to deliver safe and reliable service."[9] Further, SCE appreciates our "focus on safety and reliability risks" and "efforts to incorporate a risk based approach into the ratemaking process."[10] SCE operates under an Enterprise Risk Management framework that helps it to identify and manage risks; SCE hopes to continue to develop this approach.[11]

SCE provided an analysis of ten risk statements that serve as organizing categories for its risk control activities. For each of these risk statements, SCE describes the potential impacts of a risk event, drivers of the risk, and controls designed to reduce or manage that risk.[12] SCE generally contends that ORA and TURN propose inappropriately deep cuts to its spending to address these risks. SCE provides the following table summarizing the parties' positions ($1,000, Expense Dollars in $2012, Capital Dollars in nominal$ in 2015).[13] Note that this table reflects the positions of the parties in early stages of the proceeding, not final positions.

[8] D.14-12-025 at 4.
[9] SCE-17 at 1.
[10] SCE-15 at 1.
[11] SCE-1 at 29-30 and SCE-15 at 4.
[12] SCE-15.
[13] SCE-17 at 8.

Risk Statement	SCE Application Forecast		ORA Proposed Reductions		TURN Proposed Reductions	
	Expense	Capital	Expense	Capital	Expense	Capital
1. Conductor Failure Risk	$100,553	$272,881	$(11,820)	$(47,343)	$(3,154)	$(125,615)
2. Pole Failure risk	$46,896	$500,330	$(13,079)	$(94,675)	$(475)	$(130,074)
3. Underground Structure and Underground Equipment Failure Risk	$23,997	$81,813	$(9,670)	$(26,039)	$(9,301)	$(36,896)
4. Other Electrical Equipment Failure Risk	$258,191	$556,168	$(9,029)	$(80,502)	$(475)	$(61,533)
5. Workforce Safety and Worker Capability	$55,455	$11,384	$(6,360)	$(2,893)	$(12)	$(24)
6. Physical and Cyber Security Risk	$75,667	$77,693	$(17,394)	$(16,233)	$ -	$ -
7. Emergency or Catastrophic Incident	$17,967	$90,575	$(2,275)	$(7,879)	$(475)	$(5,163)
8. Inadequate System Capability Risk	$43,992	$924,259	$(4,544)	$(149,354)	$(475)	$(26,349)
9. Energy Supply Risk	$252,040	$116,726	$(20,415)	$(19,476)	$(6,477)	$ -
10. Information Systems Infrastructure Risk		$116,354	$ -	$(29,496)	$ -	$ -
	$874,758	$2,748,183	$(94,586)	$(473,890)	$(20,841)	$(385,654)

ORA and TURN emphatically reject SCE's characterization of their positions. TURN, for example, discusses two examples where it proposes significant *increases* relative to recorded spending levels that are significantly lower than SCE's proposed increase. TURN strenuously objects to its proposals being labeled as cuts. TURN recommends that we treat safety spending the same as all other forecasts and "determine whether the particular cost forecast is reasonable."[14]

[14] TURN OB.

Notably, the dollar values shown in the table above represent a significant portion of SCE's total request. The potential safety and risk consequences of these investment decisions are very real for customers, employees, and the public in general. We take our responsibility to review and decide these issues very seriously.

SED also prepared a response to SED's exhibit on risk. SED notes that "risk can never be eliminated, but rather a risk can only be mitigated down to an acceptable level" and recommends that "[s]electing between the various different mitigation options should factor in both relative cost and benefits and also the operator's knowledge and perspective of that particular part of the system."[15] Generally, SED also concludes that SCE's risk approach "lacks quantification" of risk.[16] SED comments that "SCE could improve its current risk management process by having a relative risk ranking model that enables incremental risk evaluations, since it could help balance affordability and risk reductions."[17] SED makes the following recommendation for SCE moving forward:

> The more that SCE can use data to support its future proposals, the less subjectivity in balancing risk trade-offs will occur. SCE should continue down the path of developing a robust quantitative approach for both risk ranking and risk mitigation.[18]

We appreciate SCE's efforts to analyze risks and make informed, reasonable investments to reduce risk and to continue to improve its quantitative approach to risk. Further, we encourage the parties to continue to engage on the subject of the appropriate balance between affordability and risk reductions going forward. We appreciate the work that many parties have done to help us evaluate this balance in this proceeding. This is a complicated question in

[15] ALJ-1 at 2.
[16] ALJ-1 at 8.
[17] ALJ-1 at 9.
[18] ALJ-1 at 9.

general and reasonable people may disagree about the appropriate balance in any particular context. Like SED, we look forward to having increasingly robust quantitative information and analysis to inform our choices in the future.

We review the specific issues below seeking to find an appropriate balance between cost and risk.

5. Policy

5.1. Use of 2013 Recorded Spending Data

One issue that arises numerous times in this proceeding is whether or not it is appropriate to use 2013 recorded data for forecasting. SCE argues that there are important adjustments made to recorded data before those data can be appropriately used for forecasting, and that requiring this across the board is an undue burden on the utility. SCE cites language from prior decisions in support of its view, and notes that if GRC schedules (either from past GRC Plans or the more recent D.14-12-025) were followed strictly, there would be no opportunity for ORA and intervenors to use 2013 data in their testimony.[19] TURN comments that the goal of reaching an accurate forecast for each specific item outweighs the disadvantages of using "unadjusted" data in general.[20] ORA suggests that the problem of "unadjusted" data is the result of unnecessary complexity in SCE's accounting system, and recommends that SCE be required to provide recorded adjusted data in the same format as its forecasts.[21] Many of the parties accuse each other of cherry-picking the instances that they recommend using 2013 data based on the impact on the revenue requirement.

While we do not make any broad statements about this issue as it applies to other cases, for this decision, we will evaluate the merits of relying on 2013

[19] SCE RB at 3-5.
[20] TURN OB at 2-7.
[21] ORA OB at 5-6.

data on a case-by-case basis. This conclusion should not be interpreted as requiring an across-the-board update of recorded data during a GRC process.

5.2. 2013 Recorded Capital Expenditures

SCE agrees to use 2013 recorded capital expenditures in all but two areas of this case. The exceptions are Palo Verde and Corporate Center, for which no party disputed SCE's forecast.[22] Other parties generally accept 2013 recorded. We adopt SCE's 2013 recorded capital expenditures and the proposed capital expenditures for the two exceptions, as summarized in Exhibit SCE-77, Appendix A.

6. Generation

6.1. Generation – Power Procurement

SCE's forecast of 2015 O&M for power procurement is $39.863 million; no party disputes this forecast. This forecast is a reduction of $1.33 million relative to 2012 recorded.[23] We find SCE's forecast of $39.863 million reasonable and approve it.

SCE requests $1.78 million and $1.85 million in 2014 and 2015, respectively.[24] These capital expenditures are for communications equipment with generators owned or contracted by SCE, allowing SCE to manage its generation portfolio.[25] ORA notes that 2013 recorded was much lower than forecast in SCE's initial testimony, and recommends that 2013 recorded values should be adjusted for inflation and used for 2014-2015, $1.030 and $1.098 million.[26] SCE argues that its forecast, unlike ORA's, is based on expected

[22] SCE-77 at 3.
[23] SCE OB at 23.
[24] *Id.* at 23-24.
[25] SCE-02 V4 at 42-43.
[26] ORA OB at 14.

numbers of new generators and the geographic locations of those generators.[27] We agree and approve SCE's forecast for 2014-2015.

6.2. Generation – Power Production

ORA describes significant challenges accounting for O&M costs of power production due to a reorganization of SCE's Power Production Department (PPD). ORA recommends that we require SCE "to provide, as part of the five years of recorded data (in nominal and base year dollars) yearly charges to expense and capital Sub-FERC Accounts within the [Project Development Division] PDD lines of business, and yearly charges to expense and capital Sub-FERC Accounts other than the PDD lines of business."[28] In rebuttal testimony, SCE noted that this would be burdensome and that ORA has not stated how this information would be used to forecast future costs. Further, SCE states that PPD follows company-wide "activity based" accounting practices.[29] While we sympathize with ORA's concern that a staff reorganization complicates analysis of historical cost data, we find ORA's request vague and agree with SCE that activity-based accounts provide appropriate historical data. ORA's request is denied. If ORA has specific questions about SCE's showing in the next GRC, it should pursue those questions at that time.

6.3. Nuclear Generation – Palo Verde

SCE owns 15.8% of Palo Verde Nuclear Generating Station (PVNGS), a facility operated by Arizona Public Service (APS). SCE requests $73.8 million in O&M, based on LRY, and $94.8 million in capital expenditures for 2013-2015.[30]

[27] SCE-18 at 6-7.
[28] ORA OB at 16-17.
[29] SCE-18 at 13-14.
[30] SCE-02 V3 at 1-2, 19.

TURN proposes disallowing half ($0.123 million) of SCE's dues to the Nuclear Energy Institute consistent with recent decisions. SCE does not rebut this proposal.[31] We find this modest adjustment reasonable and it is adopted.

No party otherwise contests these forecasts.

ORA makes four recommendations related to Palo Verde. First, ORA recommends that the Commission require SCE to present billing data from APS in a specific format in the next GRC. Such an order is not necessary; ORA can make discovery requests of this form in the next GRC. Second, ORA requests that its review of the 2012 Annual Audit Report be allowed to continue in the next GRC (despite receiving the report before the beginning of hearings in this case) and that SCE be required to provide the "results of the 'unresolved' Palo Verde audit report dispute" at that time. Again, this issue can be addressed during discovery in the next GRC, if ORA can demonstrate its relevance to that proceeding. Third, ORA recommends that SCE provide detailed reports on the $3.8 million (approved SCE share) Nuclear Administrative and Technical Manual Replacement project and how SCE ensures that PVNGS capital spending are spent on projects authorized by this Commission.[32] SCE has already provided testimony showing the completed spending on the Nuclear Administrative and Technical Manual Replacement project.[33] We do not order any additional showing at this time, but ORA may pursue its normal discovery in the next GRC.

6.4. Generation – Coal Generation (Mohave)

SCE requests $0.308 million in O&M for the Mohave Generating Station, ORA accepts this forecast, and no other party disputes it. SCE further requests

[31] TURN OB at 11.
[32] ORA OB at 17-20.
[33] SCE-02 V3 at 19.

authority to close the Mohave Balancing Account, and ORA agrees.[34] We approve the forecast and the request to close the Mohave Balancing Account.

6.5. Generation – Hydroelectric Generation

6.5.1. Hydro O&M

SCE's hydro O&M forecast has two components, a base forecast and an Operational Excellence (OpX) adjustment (a $0.225 million reduction) for the Operations account. SCE's rebuttal forecast is summarized below, with the amounts shown for FERC Account 539 as net of the OpX adjustment. SCE states that it used LRY for labor costs because these have been stable over the last three years and 5YA for non-labor because these costs have fluctuated due to weather and other factors. SCE's rebuttal position includes some reductions to FERC 536 made in response to TURN's recommendations.[35]

FERC Account	Component	Forecast Basis	Amount ($, millions)
536 - Fees	Non-Labor	5-Year Avg.	5.888
539 - Operations	Labor	LRY	19.108
	Non-Labor	5-Year Avg.	12.079
	Sub-Total		31.187
545 - Maintenance	Labor	LRY	9.436
	Non-Labor	5-Year Avg.	6.629
	Sub-Total		16.065
Grand Total			53.140

ORA proposes that LRY should be used for non-labor expenses in each of the three FERC Accounts. In support of its recommendation, ORA refers to a benchmarking study concluding that SCE's hydro O&M costs were high relative to other utility hydro systems on a per unit basis. ORA further argues that SCE was able to reduce O&M costs after implementing recommendations from the

[34] SCE-OB at 26, ORA OB at 20.
[35] SCE-18 at 24-26.

benchmarking study and that SCE's 2012 hydro O&M expenses were $12.2 million below authorized. Finally, ORA proposes a larger OpX reduction than proposed by SCE.[36] This larger OpX reduction[37] is rejected, as discussed in Section 25 below.

TURN proposes a number of adjustments. First, TURN suggests that a six-year average (including 2013, recorded) should be used for Account 536, excluding dam inspections, with 20% of the most recent dam inspections cost added back in. Second, TURN recommends excluding the San Gorgonio project costs from each of the three FERC Accounts because that project is being decommissioned. Third, TURN proposes forecasting the labor components of Accounts 539 and 545 based on a two-year average of 2012-2013 recorded, noting that 2013 is much lower than 2012, after excluding un-forecast, non-recurring severance costs. In its proposal, TURN has accepted certain technical corrections pointed out by SCE.[38]

In response, SCE argues that there is no clear trend in the recorded data, and that ORA presents an incomplete view of the benchmarking study and reaches inappropriate conclusions given that no other North American hydro systems were studied in as much detail as SCE's. SCE contends that unadjusted 2013 should not be the basis of this forecast, but does not cite any specific corrections other than those adopted by TURN. Further, SCE argues that, even though the facility no longer generates electricity, San Gorgonio costs are contractually required, and should be recovered under cost-of-service ratemaking principles.[39]

[36] ORA-7 at 15-17.
[37] ORA-19 at 23-24.
[38] TURN OB at 12-16, TURN-05 at 10-12, TURN-05A at 10-13.
[39] SCE-OB at 30-32, SCE-18 at 28-34.

We agree with SCE that there is no clear trend in recorded data for non-labor, and that a long term average is appropriate. However, we also agree with TURN that 2013 recorded data is informative for Account 536 and adopt TURN's proposal for that account. For Labor, we agree with SCE that recorded costs are steady and LRY is appropriate. In order to provide SCE an incentive to quickly reduce its expenses for San Gorgonio, we will allow only half of SCE's San Gorgonio forecast.

FERC Account	Component	Reduction ($millions)	Approved ($millions)
536 - Fees	Non-Labor	0.248	5.640
539 - Operations	Labor	0.027	19.082
	Non-Labor	0.002	12.077
	Sub-Total	0.029	31.159
545 - Maintenance	Labor	0.012	9.424
	Non-Labor	0.003	6.627
	Sub-Total	0.015	16.051
Grand Total		0.291	52.849

6.5.2. Hydro Capital

SCE's rebuttal position on hydro capital includes some adjustments proposed by ORA. ORA stipulates to SCE's revised forecast, and no other party contests the forecast.[40] We find reasonable and approve the capital forecast as follows ($ millions, nominal):

2014	2015
71.149	90.231

6.6. Generation – Gas-Fired Generation

6.6.1. Mountainview

6.6.1.1. Mountainview O & M

[40] SCE-18 at 37-38, ORA OB at 24, ORA-57R.

After accepting certain reductions and changes proposed by TURN, SCE requests $48.672 million in O&M.[41] TURN has no remaining disputes with SCE's forecast.[42]

SCE's forecast includes the levelized costs of the 2016 Hot Gas Path Inspection (HGPI) overhauls on both units; the most recent overhauls were done in 2013. SCE's forecast includes two FERC accounts: 549 (operations) and 554 (maintenance). The four components of SCE's forecast are summarized in the following table.[43]

[41] SCE OB at 37-38.
[42] TURN OB at 16.
[43] SCE-18 at 44-50.

Component	Description	Account	Forecast Basis	Amount ($, millions)
Base Forecast	Annual labor and non-labor	549 - Labor	LRY	3.790
		549 - Non-Labor	LRY	4.419
		549 - Other	LRY	0.070
		554 - Labor	LRY	3.718
		554 - Non-Labor	2008-2012 average (excluding 2009 overhaul)	8.351
Contract Services Agreement (CSA) Annual Fees	Annual fees to GE, adjusted for inflation	554 - Other	2008-2012 average	confidential
CSA Major Outage Fees	CSA fees triggered by major maintenance (e.g., HGPI)	554 - Other	2008-2012 average (levelized cost of HGPI)	confidential
Non-CSA 2016 Overhaul Cost Adjustment	Other HGPI costs	554 - Labor and Non-Labor	2009 non-labor cost deviation from 2008-2012 average, normalized over 2015-2017	1.696
Total				48.672

Of these four components, ORA disputes all except Non-CSA Overhaul Adjustment.[44]

ORA proposes a $1.7 million reduction to the Base Forecast, entirely for non-labor. ORA argues that there has been a consistent trend during 2010-2012 in non-labor O&M (both Accounts 554 and 549), and therefore bases its forecast on LRY.[45] SCE responds that there is no clear trend and that 2012 was a low year for maintenance for two reasons: fewer breakdowns and less maintenance in

[44] ORA OB at 24.
[45] ORA-7 at 31.

anticipation of the 2013 overhaul.[46] Given the variation in recorded costs and SCE's logical explanation for 2012, SCE's use of historical averaging is appropriate, and we adopt the SCE forecast.

Within the CSA Annual Fee, ORA argues for a $0.063 million reduction to the variable fee forecast. There are two major reasons for the difference. First, ORA proposes averaging 2009-2011 data only, rather than the five years used by SCE. ORA excludes 2008 because a Power Purchase Agreement (PPA) payment structure was in place at the time, but does not clearly explain why it proposes to exclude 2012. Second, ORA proposes using data on Factory Fired Hours (FFH)[47] rather than payments that are calculated based on that data, but it is unclear what the impact of this difference is.[48] There is no clear pattern in FFH over the five-year period, and FFH is not clearly related to the payment structure.[49] SCE's use of 5YA is appropriate.

For CSA Major Outage fees, ORA recommends using the average of actual 2009-2013 escalation rates, resulting in a $0.334 million reduction.[50] ORA's proposal to use more recent data is reasonable and is approved.

[46] SCE-18 at 53.
[47] SCE and ORA define the acronym FFH a number of different ways. While the exact proper terminology is unclear, it is evident that FFH refers to the number of hours the turbines operate.
[48] ORA-7 at 32-35; ORA OB at 26-28.
[49] SCE-18 at 58.
[50] ORA-7A at 35, SCE-18 at 46.

In total, we approve $48.338 million as detailed below:

Account	Component	Requested	Approved	Disallowed
549 - Operations	Labor	3.79	3.79	0
	Non-Labor	4.419	4.419	0
	Other	0.07	0.07	0
554 - Maintenance	Labor	3.913	3.913	0
	Non-Labor	9.852	9.852	0
	Other	26.628	26.294	0.334
Total		48.672	48.338	0.334

6.6.1.2. Mountainview Capital

For Mountainview capital expenditures, SCE and ORA agree to adopt 2013 recorded expenditures of $9.318 million, and SCE's forecasts of $1.327 million and $1.131 million for 2014 and 2015 respectively.[51] No party opposes these recommendations; we find them reasonable and approve them.

6.6.2. Peakers

SCE owns and operates five peakers for a total of 245 MWs; four entered operation in 2007, the fifth (McGrath) began operation in 2012.[52]

6.6.2.1. Peakers O&M

SCE requests $10.450 million in O&M. SCE's forecast uses LRY for operations (FERC Account 549, both labor and non-labor). For maintenance (FERC Account 554), SCE uses a four-year average for labor and LRY for non-labor. Due to McGrath only operating for a portion of 2012, SCE includes a $1.206 million adjustment. SCE accepts TURN's proposal to move $0.429 million in added facilities adjustments from non-labor to other within Account 549,

[51] SCE-18 at 59, SCE OB at 43, ORA OB at 29, JCE-1 at 40.
[52] SCE-02 V9.

which eliminates escalation on these costs for a savings of $0.030 million in 2015$.[53]

ORA and TURN each propose adjustments, to both the base forecast and the McGrath adjustment. ORA's total forecast is $9.711 million and TURN's is $9.786 million.

For the base forecast, ORA argues SCE's method of combining LRY and four-year averages for labor is inappropriate, and shows that this combination leads to a higher forecast than either approach applied consistently. ORA recommends using LRY for Account 554 Labor, and otherwise accepts SCE's base forecast, resulting in a total base forecast of $9.074 million.[54]

TURN's base forecast uses a two-year average of 2012-2013 for labor and non-labor in both Accounts 549 and 554. TURN notes that 2013 recorded costs were lower than SCE's forecast.[55]

SCE's McGrath adjustment was based on a sum of 2012 recorded for all of the McGrath-specific Final Cost Centers (FCCs), multiplied by three. SCE's McGrath adjustment does not include any FCCs shared in common between the Peakers.[56]

ORA proposes to take the average direct O&M from the four other Peakers, and use this average as a McGrath adjustment. ORA notes that SCE's testimony does not show that the initial months of O&M are representative for TY 2015 and that SCE has underspent authorized Peaker O&M for 2010-2012.[57]

TURN proposes to use 2013 recorded McGrath costs, noting that 2013 costs (both overall and for McGrath alone) were lower than 2012, recorded. TURN

[53] SCE-18 at 60-62, TURN-05 at 21.
[54] ORA-7 at 39-42.
[55] TURN-05 at 17-21.
[56] SCE-18 at 64-65.
[57] ORA-7 at 42-43.

further comments that 2013 is likely to be more representative than the last months of 2012 because of being further removed from construction.[58]

SCE rejects TURN and ORA proposals. In response to ORA, SCE states that some 2012 labor costs were recorded as capital due to McGrath construction, and therefore 2012 should not be used as a sole basis of the base forecast. Further, SCE notes that McGrath is approximately 50 miles further from the Peaker headquarters than any of the other peakers, increasing travel and labor expenses, and that some Peaker common FCCs will be increased by McGrath. In response to TURN, SCE argues that using recorded-unadjusted 2013 data is inconsistent with the Rate Case Plan.[59] We agree that there is significant variation FERC 554 (non-labor) and that SCE's four-year average approach is appropriate. Similarly, there is low recorded variation in FERC Accounts 549 (labor and non-labor) and 554 (labor) and LRY is reasonable. For the McGrath adjustment, we agree with TURN that 2013 is a more appropriate basis than 2012. Accordingly, we adopt the following forecast ($millions):

Account	Component	Requested	Approved	Change
549 - Operations	Labor	3.689	3.770	0.081
	Non-Labor	2.272	2.066	-0.206
	Other	0.429	0.429	0
554 - Maintenance	Labor	1.644	1.576	-0.068
	Non-Labor	2.416	2.314	-0.102
Total		10.45	10.155	-0.295

6.6.2.2. Peakers – Capital

SCE requests capital expenditures of $2.954 million in 2014 and $3.043 million in 2015. SCE claims that capital improvements that have been largely completed at the first four peakers will also be beneficial at McGrath, and

[58] TURN-05 at 18-21.
[59] SCE-18 at 63-67.

requests capital to do these projects there. SCE's request also includes additional projects at all of the peakers, including a purchase of three spare transformers (one of each of the three primary types included at each of the five peakers). The forecast also includes one assumed turbine overhaul.[60]

SBUA recommends that we reject SCE's request for spare transformers "unless SCE cannot pool shared transformers with other utilities," notes that it disfavors use of the Peakers, and that backup transformers are unnecessary because the Peakers are only used in "exceptional circumstances."[61] SCE rebuts SBUA's recommendation noting (among other things): the limited ability to share transformers among different generators (unlike the Peakers, which share a common design), long lead times for transformer orders, SCE's economic benefit estimate of 1.8, and the logistical difficulties sharing a pool of assets between utilities.[62] We agree with SCE that the reliability benefits of the spare transformers are sufficient to justify the costs, and that pooling assets between the utilities is not practical in this instance.

We approve and find reasonable SCE's capital expenditures of $2.954 million in 2014 and $3.043 million in 2015 for the Peakers.

6.7. Generation – Other

6.7.1. Solar Photovoltaic Program (SPVP) (FERC 549 and 550)

SCE requests $4.290 million ($2012) of O&M for 2015 for the SPVP. SCE also seeks a reasonableness review of recorded O&M for 2008-2012 totaling $25.960 million (nominal) and capital expenditures from program inception through 2013.

[60] SCE-18 at 66-71 and SCE-02 V9 at 20.
[61] SBUA-1 at 17.
[62] SCE-18 at 69-70.

SCE's TY 2015 O&M forecast consists of $2.206 million for labor and non-labor, in addition to $2.084 million for rooftop lease expenses.[63] ORA accepts the lease expenses, but recommends $1.277 million for labor and non-labor. ORA's recommendation is based on its attempt to exclude construction costs from the O&M forecast, based on analysis of a specific contract.[64] SCE argues that ORA's approach does not account for O&M performed by SCE personnel.[65] SCE, however, does not directly show how construction costs are excluded from its O&M forecast. TURN proposed reducing SCE's added facilities costs and making these costs not subject to escalation.[66] SCE partially accepts TURN's proposal, but shows that two additional facilities were added that were left out of TURN's forecast.[67] Accordingly, we adopt ORA's forecast of $1.277 million for labor and non-labor, SCE's revised forecast of $0.142 million in other or added facilities costs, and SCE's forecast of $2.084 million for leases for a total of $3.503 million, as shown below. Added facilities costs are not subject to escalation.

	FERC Account	SCE Request	Adopted
		($, millions)	
Labor	549	0.555	0.320
Non-Labor	549	1.509	0.957
Other	549	0.142	0.142
Leases	550	2.084	2.084
Total		4.290	3.503

SCE's 2008-2012 O&M expenses are subject to reasonableness review in this GRC. ORA argues that SCE has exceeded the $15.036 million (2008$) reasonable cost estimate adopted in D.13-05-033 and specifically contests a $10.1

[63] SCE-18 at 72.
[64] ORA OB at 34-37.
[65] SCE OB at 48-50.
[66] TURN-5A at 22.
[67] SCE-18 at 77-78.

million ($9,672,063 in 2008$) termination payment to SunPower on the grounds that the contract was imprudent at the time of signing. ORA argues that, when SCE signed the SunPower contract in 2010, prices were declining, and it was imprudent to purchase a large volume at a fixed price given "possible barriers" to building large amounts of utility owned generation.[68] SCE criticizes ORA's analysis as being based on perfect hindsight. SCE argues that the contract was prudent at the time of signing, pointing primarily to the volume discount structure as evidence, and claiming that without the termination fee, the unit price would have been higher.[69] SCE quantifies the benefits of termination at the time of termination as $203.7 million and contends that this is the appropriate time of analysis.[70] However, SCE's testimony does not quantify the benefits at time of signing, and therefore does not establish that the contract, including the termination fee, was prudent. We agree with ORA, and accordingly disallow the termination payment. To be clear, we are not concluding that contracts structured in this way are generally imprudent, merely that SCE has not met its burden of proof in this instance. SCE's other recorded O&M costs for 2008-2012 are approved.

SCE's capital expenditure request of $0.425 million for 2014 and $1.035 million for 2015 is uncontested.[71] This request is reasonable and is approved.

SCE requests authority to eliminate the Solar Photovoltaic Program Balancing Account (SPVPBA). ORA agrees.[72] We approve this request, noting that the balance of the SPVPBA must be adjusted for the disallowed SunPower termination payment discussed above.

[68] ORA-7 at 52-54 and ORA OB at 39-41.
[69] SCE-18 at 80, SCE OB at 52, and SCE RB at 20-21.
[70] SCE Comments at 1-2.
[71] SCE-18 at 79, ORA OB at 37.
[72] ORA-7 at 48.

6.7.2. Catalina (FERC 549.140)

ORA and SCE agree to TURN's proposed average of several years of recorded costs, excluding one-time expenses, to calculate an O&M forecast of $4.360 million.[73] TURN's approach is consistent with our forecasting guidelines, and we approve this forecast.

For capital expenditures, SCE and ORA agree to TURN's alternative recommendation, except for Allowance for Funds Used During Construction (AFUDC) and capitalized taxes. As agreed by SCE and ORA, this forecast is: $1.255 million in 2014 and $2.509 million in 2015.[74] TURN's primary recommendation is that cost recovery be limited to $5.1 million.[75] In support of this recommendation, TURN notes that the Pebbly Beach Generating Station Generation Automation Project (PB Project) was originally a $2 million project in the 2009 GRC, has doubled in cost since being approved in the 2012 GRC, serves fewer than 2,500 customers, that completion has been delayed at least into 2015, and that the project benefits have shifted over time and now do not include monetary benefits.[76] In summary, TURN argues that SCE has not demonstrated that the project should be funded beyond the $4.6 million approved in the 2012 GRC and proposes that only $5.1 million (costs through 2013) should be approved, using an assumed online date of July 2015. This recommendation includes disallowance of AFUDC and capitalized property taxes. TURN cites examples from other jurisdictions in support of the AFUDC and tax proposal, and argues that SCE's mistake in project management led to the delay and resulting costs.[77] SCE's responses to TURN's concerns are: that there were

[73] SCE-18 at 89-90, ORA-57R at 3, and TURN OB at 22-23.
[74] JCE-V3A at 77.
[75] SCE-18 at 90-92, ORA-57R at 3, and TURN OB at 23-24.
[76] TURN-5 at 25-28.
[77] TURN OB at 26-31.

"valid" reasons including GRC delays, project sequencing, and other emergent priorities; recovery of AFUDC is appropriate; TURN's AFUDC references are inapplicable; property tax is based in part on CWIP; and recovery of capitalized property tax is appropriate.[78] We largely agree with TURN – even though some of the reasons for the delay were outside SCE's control, some were not and SCE has not justified the PB Project at this level of expense. However, because some of the reasons for delay during 2012 were beyond SCE's control, we allow a larger portion of the AFUDC and capitalized taxes. As shown in the table below, in addition to the $5.1 million in direct capital expenditures proposed by TURN through 2013, we also allow the various capital loadings for the PB Project, but only through the end of 2013; these loadings are automatically calculated by the RO computer model.

	Capital Expenditures - Direct Costs (Millions of $)[79]				
	Through 2013 *	2014	2015	2016	2017
SCE Request	$5.127	$1.255	$2.509	$0.310	$0.060
Adopted **	$5.127	$0.000	$0.000	$0.000	$0.000
Difference	$0.000	$1.255	$2.509	$0.310	$0.060
* Direct expenditures through 12/2013 were obtained from TURN-6 at pages 39-40.					
** Loadings (AFUDC, Capitalized Property Taxes, etc.) are not shown. They will be calculated by the RO model and are only allowed through the end of 2013.					

6.7.3. Fuel Cells (FERC 549)

SCE requests $0.669 million in O&M for its fuel cells on various university campuses.[80] ORA proposes two reductions: one based on a different assumption about fuel cell availability ($0.086 million), and reducing labor by one half of an

[78] SCE OB at 54-58.
[79] JCE-V3A at 77.
[80] SCE-18 at 85.

Full-Time Equivalent (FTE) ($0.057 million) on the grounds that SCE's justification for the FTE is inadequate.[81] TURN argues for a reduction of one third of an FTE arguing that we previously approved one FTE on the basis of three fuel cells, but now there are only two.[82] We agree with TURN that two thirds of an FTE is adequate given the reduced scope and reduce SCE's labor forecast by $0.037 million. For the non-labor costs, based on confidential historical availability data,[83] we conclude that a reduction of $0.043 million is appropriate. Our approved O&M forecast is, in millions:

	SCE Request	Approved
Labor	$ 0.113	$ 0.076
Non-Labor	$ 0.556	$ 0.513
Total	$ 0.669	$ 0.589

SCE requests authority to eliminate the Fuel Cell Program Memorandum Account (FCPMA).[84] ORA agrees.[85] No party disputes this request, and we authorize SCE to eliminate FCPMA.

SCE's capital expenditures for the fuel cell program are addressed in ERRA; no capital expenditures are approved here.

7. Transmission and Distribution (T&D)

SCE states that its "Transmission and Distribution Business Unit (T&D) is responsible for planning, engineering, constructing, operating, and maintaining the transmission and distribution facilities required to safely and reliably deliver electricity to SCE's five million customers throughout [SCE's] 50,000 square-miles of service territory."[86] At the end of 2012, T&D infrastructure included over

[81] ORA OB at 42-44, SCE-18C at 86.
[82] TURN OB at 31-32 citing D.10-04-028.
[83] SCE-18C at 87.
[84] SCE-2 V10 at 28.
[85] ORA OB at 42.
[86] SCE-3 V1 at 1.

90,000 miles of distribution lines, over 1.4 million poles, and over 400,000 underground structures. T&D is SCE's largest operating unit, including "almost 8,600" people. SCE's transmission costs are largely recovered through rates set by FERC.[87]

ORA suggests that many of the issues in this area are matters of judgement, namely what is the appropriate balance between reliability and costs. ORA claims that 2015 shows dramatic funding increases, and that new capital categories are created in 2014-2015; ORA questions the urgency of these increases. Similarly, ORA questions SCE's claims that aging infrastructure needs replacement, and suggests that aging infrastructure does not necessarily mean that reliability is compromised.[88]

We note that this is not the only proceeding dealing with SCE's T&D infrastructure. For example, both the Distributed Resource Plan (Rulemaking (R.) 14-08-013) and Interconnection (R.11-09-011) proceedings are evaluating changes in the way that this infrastructure should be planned, paid for, and managed. SCE, the Commission, and the industry are continually transitioning to newer technologies and approaches to these challenges. We encourage SCE to use the funds authorized in this decision to adopt improved technologies and approaches to the extent practicable.

7.1. T&D – Policy

SCE states that T&D is guided by "three areas of focus – safety, reliability, and affordability" and "cornerstone values of compliance and operational excellence."[89]

[87] SCE-3 V1 at 1.
[88] ORA OB at 45-46.
[89] SCE-3V1 at 3.

7.1.1. Safety and Reliability Investment Incentive Mechanism (SRIIM)

In the last several GRC's, we have adopted some form of Reliability Investment Incentive Mechanism (RIIM) to require SCE to spend certain funds on reliability as authorized, or make refunds to ratepayers. RIIM includes two components: capital spending and staffing. In the capital spending component, there are two categories: Reliability Investment (which we refer to as "core") and High Priority, with the spending target for Reliability Investment adjusted based on spending in High Priority. In the 2012 GRC, we adopted a CUE-SCE settlement related to RIIM and directed SCE to consult with other parties about the feasibility of addressing safety issues in RIIM or a similar program in this GRC. We also ordered SCE to hire an outside auditor to report on RIIM.[90]

In this proceeding, SCE proposes to continue a modified RIIM. SCE proposes seven categories of capital investment in safety or reliability areas to be core RIIM-eligible; the combined authorized forecast for these categories would be the RIIM capital target. The seven categories are: Worst Circuit Rehabilitation (WCR), Underground Cable Life, Cable-in-Conduit (CIC) Replacement, Underground Switch, Underground Structure Replacement, Circuit Breaker Replacements, and Substation Transformer Replacement. Further, SCE proposes three categories of High Priority capital expenditures that are influenced strongly by external factors: customer growth, storms, and claims. Expenditures in the combined High Priority areas would be summed and the difference relative to authorized spending in these high priority areas would be added (or subtracted) to the core RIIM capital target. For example, if the amount spent on the High Priority areas is above authorized, the core RIIM capital target would decrease. For the staffing target, SCE identifies several workforce categories and proposes a

[90] D.12-11-051 at 692-701.

target number of employees approximately equal to the headcount at the end of 2012. SCE would refund $20,000 for each employee shortfall relative to the target, up to 50 employees short, and $80,000 per employee thereafter. SCE proposes that, if any employee shortfall that develops in the fourth quarter of 2017, it should have the first quarter of 2018 to address the shortfall.[91] SCE initially requested a reduction in the headcount target by one-fifth of any percentage reduction in training amounts, but has withdrawn this proposal.[92]

ORA discusses concerns that 2013 staffing are below the target level adopted in the last GRC and that no ratepayer refund associated with this shortfall is apparent in SCE's application. ORA recommends that we order SCE to make refunds associated with this shortfall, in the absence of further documentation from SCE. ORA also appears to oppose any staffing level target being included in RIIM in this GRC.[93]

SCE responds that ORA misunderstands the goal of RIIM's staffing targets and that it hopes to meet the staffing target by 2014. If it fails to meet the target, SCE states it will make appropriate refunds.[94] We note that in SCE's Advice Letter 3191-E, SCE claims to have met the staffing target.

TURN and CUE present a joint statement on the capital spending component. They propose a one-way balancing account so that underspending on High Priority categories should be added to the core capital spending target, but not in the reverse. For example, if SCE spends more on the High Priority categories than authorized, it would still be subject to the capital spending target for the core RIIM categories, without an adjustment. In effect, SCE would need to look to other funding sources, not the RIIM categories, to fund the additional

[91] SCE-3V1 at 23-28.
[92] SCE RB at 30-31.
[93] ORA-9 at 62-66; ORA OB at 52-53.
[94] SCE-19V1 at 11-12.

High Priority work. TURN and CUE argue that SCE should not be able to divert funding away from the core RIIM categories. TURN also initially proposed (and still supports) an alternative – eliminating the capital spending component altogether; CUE opposes this alternative. CUE further recommends we preclude SCE from diverting any pole replacement money to the High Priority categories.[95]

SCE argues that this proposed one-way balancing account treatment should be rejected. Generally, SCE argues that High Priority work cannot be delayed to meet core RIIM targets and that shareholders should not be required to fund these functions. Further, SCE claims that a limiting factor in doing this work is that the same employees perform the work in both the core RIIM categories and the High Priority categories; therefore, if extra High Priority work is required, less core RIIM work can be completed.[96]

In our review of RIIM, we first note that the relationship between safety, reliability, and resiliency is complex. As SED observes, sometimes an investment in one category may serve to reduce risk in another. In other instances, there is an inverse relationship between safety and reliability: a choice (e.g., a setting on a circuit breaker) may be "good" for safety but "bad" for reliability, or vice versa.[97] Our goal is to promote safety, reliability, and resiliency in the most cost-effective manner. A tool like RIIM is very blunt, and indeed, this is appropriate for our goal. In this proceeding, we cannot and do not seek to fine-tune SCE's approach to managing risk. Instead, we seek to create incentives that align SCE's financial interests with the community's interests in safety, reliability, resiliency, and cost. Encouraging SCE to spend its authorized capital

[95] Attachment to TURN OB at 3; Attachment to CUE OB; CUE OB at 7-9.
[96] SCE-19V1 at 13; SCE OB at 67.
[97] ALJ-1.

forecast on key programs to meet this goal and retain employees in classifications responsible for this work is reasonable. Therefore, it is reasonable to adopt some type of RIIM-mechanism. In order to reflect the increased direct focus on safety, RIIM should be renamed the SRIIM. Even though this proceeding did not precisely follow the framework of D.14-12-025, this is consistent with the goals of that decision.

No party disputes that the categories that SCE proposes for the RIIM capital target, High Priority categories, or staffing target are inappropriate. We find that the proposed categories are reasonable and appropriate to meet our goal. Similarly, SCE's proposed High Priority categories (customer growth, storms, and claims) are unopposed and are reasonable. Further, SCE's staffing target proposal (2,225 employees in the categories identified at SCE-3V1 at 27) is essentially unopposed.[98] We find it reasonable and adopt it.

For the capital spending component, we find that SCE's proposed method is reasonable with modification. Like TURN and CUE, we find that it is suboptimal to divert funding from core SRIIM categories to the High Priority categories, potentially delaying important work. Like TURN,[99] we mostly discount SCE's argument that because the same staff performs both the High Priority and core SRIIM categories, SCE cannot necessarily meet both goals at once. While this may be true in some cases, SCE's recorded spending in 2009-2011[100] suggests that this is not always a limiting factor. Moreover, given the limited set of core RIIM categories, SCE should have more flexibility to meet both goals now than in the past. However, SCE's response that it is unreasonable

[98] ORA expresses concerns about whether or not SCE met *past* staffing targets; past targets are a separate issue that we need not resolve here. ORA does not present a clear counter-proposal or opposition to SCE's proposed forward-looking target.
[99] TURN OB at 35.
[100] SCE-19V1 at 13.

to ask shareholders to fund core utility work has merit. Therefore, we adopt the TURN/CUE proposal with the following modifications. Overspending in the High Priority categories can offset underspending in the core SRIIM categories if two conditions are true: the overspending in High Priority categories exceeds 10% of the adopted forecast for those categories and SCE's actual rate of return on rate base for the period does not exceed the authorized rate of return. The first 10% of overspending on High Priority categories cannot be used to offset underspending in the core SRIIM categories under any circumstance. These modifications are designed to ensure that SCE will look to other sources of funding before reducing core SRIIM spending in the event of overspending on the High Priority categories. In the event that High Priority spending significantly exceeds the adopted forecast, SCE has some protection.

7.2. T&D – Engineering and Grid Technology

T&D's Engineering Department performs technical analyses related to load growth and grid changes; designs electrical, civil engineering, and structural components of projects; and manages efforts to evaluate and implement grid technologies.[101]

7.2.1. Centralized Remedial Action Scheme (CRAS)

SCE states that it must plan for power flows on its transmission system, both under normal and emergency/unusual conditions in order to avoid damaging equipment or outages. To address this need for new generator interconnections, SCE can build redundant transmission or Remedial Action Schemes (RAS). RAS can shed generation and/or load to handle a contingency by reducing power flows.[102]

[101] SCE-3V2 at Summary.
[102] SCE-3V2 at 11-12.

SCE argues that, due to numerous, geographically clustered interconnections of intermittent generators, complexity of system protection has increased significantly. SCE states that it has initiated Centralized RAS (CRAS) "to address these issues and the limitations of stand-alone RAS."[103] SCE suggests that a key benefit of CRAS over RAS is that the logic control is centralized and approximately 27% fewer relays are needed.[104] Further, CRAS allows for a more "carefully limited solution" to contingencies than RAS by using more arming points to treat generation customers individually rather than in groups and being adaptable over time.[105]

We approved $58.1 million (CPUC jurisdictional portion) in SCE's 2009 GRC, which SCE largely delayed spending. In the 2012 GRC, we only approved SCE's 2010 capital spending and the balance of its 2010 forecast, a total of less than $7 million, directing SCE to perform more analysis on the viability of using existing RAS technology.[106]

For CRAS, SCE's test year O&M request is $0.043 million.[107] SCE's total capital expenditure request is (total company nominal, $000s) is shown below.[108]

2014	2015	2016	2017
$10,326	$11,299	$23,031	$34,825

ORA recommends a one-way balancing account for CRAS so that in the future, costs may be evaluated more accurately and that SCE should be required to identify labor and non-labor costs for relays and telecommunications.[109]

[103] *Id.* at 12.
[104] *Id.* at 15.
[105] *Id.* at 18-19.
[106] D.12-11-051 at 124-127.
[107] JCE-3 at 101.
[108] SCE-3 V2 A at 11, JCE-3 at 102-103.
[109] ORA-10 at 23 and ORA OB at 57.

TURN objects to SCE's request, arguing that SCE has not shown the benefits of CRAS exceed costs and has not shown that stand-alone RAS is not viable.[110] More specifically, TURN asserts that CRAS's benefit of reducing generation curtailment is not quantified and "are largely illusory and benefit the generation owners."[111] TURN estimates that the renewable energy lost to RAS-related curtailment is much lower than that lost to economic curtailment, and suggests that this makes the benefit of CRAS "even more fleeting."[112] In the only load curtailment event related to RAS since 2000, the impact on load was short in duration and would have also occurred if CRAS was in place at the time.[113] TURN claims that the incremental costs of CRAS over additional RAS are significant.[114]

TURN recommends reducing SCE's O&M request by $43,000 and denying all of SCE's requested capital expenditures.[115]

TURN's argument that the benefits of CRAS are not quantified is compelling; indeed, we would like to see more concrete cost-benefit analysis than SCE has provided here. However, the intuitive appeal of the CRAS benefits that SCE describe are strong and the outcome of any effort to quantify them at this time may be primarily driven by preliminary assumptions (number of interconnections, policies on economic curtailment, etc.). As a matter of policy, this Commission supports a future with renewable generation resources operating efficiently on the grid and seeks opportunities to improve grid operations with respect to such resources. CRAS appears to be such an

[110] TURN OB at 37-38.
[111] *Id.* at 40.
[112] TURN OB at 46; TURN-80B; and TURN-85.
[113] TURN-35.
[114] TURN OB at 46-48.
[115] TURN-3 at 14 and JCE V2 at 607 and 692-693.

opportunity, and may be cost effective in some scenarios; accordingly, we adopt a partial funding compromise.

SCE's recorded capital expenditures for 2013 are approved; capital expenditures for later years and O&M are denied. SCE may reapply for the denied capital expenditures in its next GRC, if it provides a detailed cost-benefit analysis in support of that request.

7.2.2. Engineering and Grid Technology O&M

SCE requests $51.223 million in O&M for Engineering and Grid Technology. ORA agrees with this forecast.[116] As detailed in ORA's brief, both ORA and SCE made concessions on various components of this forecast.[117]

This forecast is summarized in the following table:

FERC Account(s)	Subject	Activities	Forecast Basis
560.220	Generator Interconnection Contract Development	Manage interconnection process	2012 recorded
560.220	Transmission Line Rating Study	Study and verification process to comply with G.O. 95 and North American Electric Reliability Corporation (NERC) recommendations	Cost per verification times spans to be studied, plus remaining costs of LiDAR contract
560.220	Transmission Planning	Identify system modifications; participate in setting standards	2012 recorded plus two positions
560.220 & 588.220	Fiber Optic Network	Maintenance and inspection of communications network	2012/2013 recorded plus incremental inspection costs to implement new rules on fire hazards
560.220 & 588.220	Grid Engineering	Root cause analysis; engineering studies; updating standards; assisting field personnel; designing systems and controls.	2012/2013 recorded
560.221	Reliability Standards	Manage regulatory compliance; respond to information requests;	2012 recorded plus two positions

[116] ORA-57R.
[117] ORA OB at 53-55.

	Compliance	develop policy recommendations	
560.260 & 580.260	Grid Technology Integration	Technology studies; supporting development of industry standards; managing demonstration projects	2013 expenses
560.260 & 580.260	IT Chargebacks – Transmission	Laptops, phones, etc. for T&D personnel	2012 recorded
588.220	Load Side Support	Diagnose customer problems related to power quality, and collaborate on solutions	Labor: 2012 recorded, plus two additional employees; Non-Labor: three-year average
588.260	Operational Process Engineering	Expenses related to capital and non-capital projects and field equipment	2012 recorded
588.261	Consolidated Mobile Solutions Benefits		
920.220	Real Properties	Acquire and manage land rights	2012 recorded

Note that TURN proposes a $9,000 disallowance for Grid Technology Integration and Miscellaneous. This is discussed below in Section 28.1. We reduce the forecast for FERC Account 588.260 by $165,000[118] of $1.866 million to account for the reductions in capital expenditures discussed in Section 7.2.3 below. All other components ($51.058 million) of this forecast for O&M are reasonable and are approved.

7.2.3. Engineering and Grid Technology Capital

SCE requests $192.397 million (total company, nominal$) in capital expenditures between 2013 and 2017, of which over $52 million is related to the CRAS project discussed in section 7.2.1 above. This request is summarized below.[119]

[118] Calculated by multiplying the ratio of allowed to requested capital expenditures by the requested O&M.
[119] SCE-19 V2 at 10.

SCE Capital Request - Engineering and Grid Technology (Nominal $000)		
	2014	2015
Fiber-Optic Network Maintenance	$ 2,759	$ 2,822
EVTC Laboratory Expansion Project	$ 1,458	$ 1,494
Large Energy Storage Test Apparatus	$ 852	$ 206
Distributed Energy Storage Integration (DESI)	$ 576	$ 4,388
Westminster Labs Upgrades	$ 3,515	$ 4,023
Equipment Demonstration and Evaluation Facility	$ 3,274	$ 4,365
Wide Area Voltage/VAR Control System	$ 800	$ 529
Geographical Information System	$ 16,489	-
CRAS Project Phase	$ 9,772	-
CRAS Program Phase	$ 554	$ 11,300
Phasor/WASAS	-	-
DFR/PMU Infrastructure Replacement	$ 5,872	$ 6,542
Phasor Advanced Data Analytics	$ 1,200	$ 7,700
Benefits	$ (1,874)	$ (5,313)
Total Capital	$ 4 5,248	$ 38,057

With the exception of CRAS, no party opposed this request. Nevertheless, we briefly discuss each item that is greater than $1 million in 2015.

7.2.4. Fiber Optic Network Maintenance

This work includes replacing capital equipment such as fiber optic cables and microwave systems. The forecast is based on last recorded year.[120]

7.2.5. Electric Vehicle Technical Center (EVTC) Laboratory Expansion Project

SCE states that its needs for testing vehicles and stationary batteries have outgrown the existing center. This request would add dynamometer capability for heavy duty vehicles and additional equipment and facilities. The forecast is

[120] SCE-3 V2 at 34.

based on specific capital additions each year, and totals $7.696 million from 2013 to 2017.[121]

7.2.6. Distributed Energy Storage Integration (DESI)

These pilot deployments of three storage systems up to 2.0 MW and capable of discharging for up to 2 hours are intended to help SCE develop deployment plans for energy storage. Additionally, SCE plans to procure two smaller (25 kilowatt (kW)) storage systems. SCE will test the systems for benefits including feeder load relief and voltage support. The total capital cost of this project is $13.409 million from 2013 to 2017.[122]

7.2.7. Westminster Labs Upgrades

SCE claims its labs enable it to evaluate and demonstrate new technologies, in support of SCE's Smart Grid Strategy and Deployment Plan. SCE requests to upgrade its laboratory capabilities. SCE claims that there are "scant" options for third parties to provide the laboratory services that SCE seeks and that testing "SCE device interoperability" can only be done cost effectively in SCE labs. There are four upgrades SCE seeks:

- Enhanced real time simulation of protection and control equipment by adding processing power. This addition would allow SCE to do Western Electricity Coordinating Council (WECC) wide simulations and run multiple tests simultaneously for programs such as CRAS. SCE claims that increased use of such simulations could save $150,000 per transmission line study.
- Substation automation simulations, in order to achieve benefits of newer network technologies within substations automated with older technology.
- Communications including cybersecurity, in order to develop solutions for NERC Critical Infrastructure Protection (CIP)

[121] *Id.* at 51-52.
[122] *Id.* at 55-57.

standards. This upgrade will also provide support for other labs and test communications equipment for CRAS and other applications.

- And other miscellaneous upgrades, including replacing older equipment.

SCE's total forecast is $13.5 million.[123]

7.2.8. Equipment Demonstration and Evaluation Facility (EDEF)

SCE proposes a new EDEF to test equipment in a "real SCE grid environment" that is not an active customer circuit. SCE claims that this will allow SCE to conduct energized tests of emerging technologies that would be too disruptive on customer circuits. Testing capabilities would include: high impedance faults, construction and installation methods, and distribution substation automation. SCE expects EDEF to reduce implementation timelines and costs due to more efficient pre-pilot processes.[124]

7.2.9. Phasor Program

SCE has a contractual commitment to WECC to complete the Phasor Program, which includes three of the projects in this request. We discuss the three (Phasor System, Digital Fault Recorded/Phasor Measurement Unit [DFR/PMU] Infrastructure Replacement, and Phasor Advanced Data Analytics) in combination. The objective of this project is to provide WECC and California Independent System Operator (CAISO) information on the bulk power system that may reduce wide-scale outages. SCE forecasts completion of the Phasor System, a software and data collection project, in 2013. The DFR/PMU project replaces obsolete DFRs and PMUs that were installed in the 1980s through 2000s with new DFR/PMUs. SCE intends to upgrade four substations per year and

[123] *Id.* at 57-67.
[124] *Id.* at 67-71.

add or replace 17 DFR/PMUs from 2013 to 2017. The Advanced Phasor Data Analytics program will increase SCE's ability to use the data collected by PMUs and support increased variable generation. The two primary benefits of this data are reduced outages and improved transmission line usage. Cost estimates are based on forecast activities and vendor information.

7.2.9.1. Engineering and Grid Technology Capital Discussion

We disallow a portion of this request. SCE has not shown that portions of the Westminster Lab Upgrades related to WECC-wide simulations and developing devices compliant with NERC CIP are SCE specific problems that should be funded by ratepayers. Further, portions of the Westminster upgrades are related to CRAS, which we have also partially disallowed. Therefore, we reduce the Westminster Upgrades request by half for each year. Similarly, we disallow all EDEF expenditures because SCE has not shown that the technical problems it would address are unique to SCE and that other more cost-effective options do not exist for doing this research. All other capital expenditure requests for Engineering and Grid Technology are approved.

	2014	2015
Total Capital Request	$45,248	$38,057
Disallowances		
Westminster Labs Upgrades	$1,757.50	$2,011.50
Equipment Demonstration and Evaluation Facility	$3,274	$4,365.00
Total Capital Disallowances	$5,032	$6,377
Total Capital Allowed	$40,217	$31,681

7.3. T&D – Electric System Planning

SCE performs system planning capital projects to accommodate load growth, maintain reliability, accommodate generator interconnections, and

respond to customer requests for non-standard service. SCE divides these projects into five categories:

1. Transmission Planning Projects are large scale transmission upgrades, including four sub-categories: grid reliability, transmission system generator interconnection, other transmission planning projects with CPUC costs over $1 million, and other transmission planning projects with CPUC costs less than $1 million.
2. The Load Growth Planning Program increases system capacity through projects at a variety of scales. Sub-categories are: A-bank plan, subtransmission lines plan, subtransmission volt-ampere reactive (VAR) plan, and Distribution Substation Plan (DSP).
3. The System Improvement/Reinforcement Program includes smaller projects upgrading substation equipment and the distribution system to handle load growth.
4. The Generator Interconnection Program includes projects to interconnect generators, who chose to have SCE do this work.
5. Added Facilities projects provide non-standard service to customers based on their requests. Projects may be partly customer-funded and partly ratepayer-funded.[125]

SCE's forecast[126] for these categories is described below (millions of nominal$), along with a summary of the approved forecast.

	SCE Request		Adopted	
	2014	2015	2014	2015
Transmission & Interconnection Planning Projects	580.662	214.934	580.662	214.934
Load Growth Planning Programs	371.272	412.991	371.272	412.991
System Improvement / Reinforcement Programs	114.432	108.903	111.861	106.137
Generator Interconnection Program	11.993	11.617	11.993	11.617
Added Facilities Projects	32.466	24.290	32.466	24.290

[125] SCE-3V3 at 1-2.
[126] SCE-19V3A at 2.

Total	1,110.826	772.735	1,108.254	769.969

ORA makes a number of high level recommendations and comments related to SCE's showing. ORA proposes a blanket 21% reduction to SCE's forecasts for 2014 and 2015 on the basis of SCE's "underspending" in 2013 relative to its forecast. Further, ORA proposes that SCE be required to include more detail in its showing in the next GRC, suggesting disaggregation of costs according to the sub-categories enumerated above and "something akin to zero based budget accounting." Finally, ORA notes that the number of new meters (discussed below in Section 16) has implications for this subject area.[127]

SCE rejects ORA's recommendations. SCE claims that ORA's proposed 21% reduction does not meet ORA's burden of production and recommends that we order ORA to expressly analyze individual capital projects in future GRCs. SCE claims that its showing in this GRC contains at least the same level of detail as prior GRCs and that the RO model also includes detail on jurisdictionalization.[128]

Like SCE, we find that ORA's 21% reduction is not persuasive. Underspending (or overspending) in a broad category in one year does not directly show error in forecasts for individual sub-categories in other years. However, we disagree with SCE's apparent view that ORA should be barred from making any blanket recommendations in future GRCs and decline to adopt SCE's proposed constraints on ORA's showing. Similarly, we decline to adopt any new broad requirements for SCE's showing in this area. We do, nevertheless, agree with ORA that, in future GRCs, SCE should provide clear unit cost forecast information for the major types of equipment relevant to this topic. SCE should clearly present the number of units required for each project

[127] ORA-10 at 27-30.
[128] SCE OB at 70-77.

or program so that the total cost forecast for the project or program can be compared to the sum of the unit costs.

7.3.1. Transmission Planning Projects

SCE identifies eight major (>$1 million) grid reliability projects, ten transmission generator interconnection projects, and several smaller (<$1 million) projects.[129] Most of these are uncontested. We find reasonable and adopt SCE's forecasts for the uncontested projects.

7.3.1.1. Victor 220/115 kilovolt (kV) Substation

SCE has installed third and fourth A-bank transformers and a new 115 kV switchrack. ORA opposes the fourth A-bank, claiming that SCE did not justify this expenditure. ORA proposes a $0.050 million disallowance in 2013.[130] SCE claims the fourth A-bank was needed to ensure reliable service during construction.[131] We find SCE's rationale reasonable and make no disallowance.

7.3.1.2. Other ORA Proposals

ORA proposes a $1 million disallowance for upgrades at the Cal Cement Substation on the grounds that a customer should pay these costs.[132] SCE explains that the relevant equipment is entirely network facilities serving multiple customers.[133] We agree with SCE that costs of upgrades to network facilities are appropriately recovered from ratepayers in general and approve the Cal Cement upgrades.

ORA proposes a $0.027 million disallowance on the basis of allocating certain costs to FERC.[134] SCE explains that no part of the relevant equipment is

[129] SCE-3V3 at 19-36.
[130] ORA-10 at 31-32.
[131] SCE-19V3 at 6-7.
[132] ORA-10 at 34.
[133] SCE-19V3 at 7.
[134] ORA-10 34.

FERC jurisdictional.[135] SCE's explanation is reasonable, and we adopt SCE's forecast.

ORA proposes a reduction to SCE's forecast of small projects on the grounds that discovery information and SCE's testimony show different numbers.[136] SCE explains that ORA is apparently confusing the gross forecast with the forecast net of customer contributions.[137] SCE's explanation is reasonable, and we adopt SCE's forecast.

Consequently, we find reasonable and adopt SCE's forecasts for other transmission planning projects.

7.3.2. Load Growth Planning Projects

As shown above, load growth planning projects represent the largest category of electric system planning costs. ORA's primary proposal in this area is the blanket 21% reduction that we rejected above. Specific issues are addressed below.

SCE's A-bank plan seeks to provide adequate A-bank transformer capacity to meet peak loads under base case and N-1 contingency[138] conditions. SCE replaces or expands equipment to meet peak loads only if growing load cannot be rebalanced among substations to avoid the expense. SCE identifies 12 A-bank projects with costs greater than $1 million for a total CPUC-jurisdictional cost of $396 million during 2013-2017.[139] We find SCE's forecast of A-bank plan expenditures for 2014-2015 reasonable.

SCE's subtransmission line plan seeks to provide adequate 66kV or 115kV capacity to meet peak loads at B-substations under base case and N-1

[135] SCE-19V3 at 7-8.
[136] ORA-10 at 38.
[137] SCE-19V3 at 8.
[138] N-1 contingency refers to the condition of one critical element of system equipment out of service.
[139] SCE-3V3 at 36-46.

contingency conditions. SCE replaces or expands equipment to meet peak loads only if growing load cannot be rebalanced among subtransmission lines to avoid the expense of new subtransmission capacity. SCE identifies 22 subtransmission projects with costs greater than $1 million for a total CPUC-jurisdictional cost of $213 million during 2013-2017.[140] We find SCE's forecast of subtransmission plan expenditures for 2014-2015 reasonable.

SCE's DSP seeks to provide adequate B-bank and distribution circuit capacity to meet peak loads under base case and N-1 contingency conditions. SCE replaces or expands equipment to meet peak loads only if growing load cannot be rebalanced among B-banks or distribution circuits to avoid the expense of new capacity. Typical projects include adding or upgrading B-banks or developing new B-substations. SCE identifies 32 DSP projects with costs greater than $1 million for a total CPUC-jurisdictional cost of $535 million during 2013-2017.[141]

ORA recommends a $35 million disallowance to SCE's 2015 forecast because "that unit cost is excessive" in reference to DSP circuit projects associated with substation upgrades.[142] SCE explains that ORA misunderstands the forecast and that ORA has apparently concluded that the entire 2015 capital expenditure supports the single project completed that year rather than the 14 projects expected to be completed in 2016.[143] We agree with SCE that ORA has not explained a valid basis for its proposed reduction. We find SCE's DSP forecast for 2014-2015 reasonable.

[140] SCE-3V3 at 47-61.
[141] SCE-3V3 at 64-66.
[142] ORA-10 at 48-50.
[143] SCE-19V3 at 10-11.

SCE requests $13.251 million in 2015 (nominal) for land purchases for two projects.[144] This expenditure is uncontested, and is approved.

7.3.3. System Improvement/Reinforcement Program

This program includes six cost categories.

7.3.3.1. Substation Equipment Replacement Program (SERP)

SERP evaluates and, if necessary, replaces or adds substation equipment (e.g., circuit breakers, grounding) to ensure safe operation and avoid equipment damage. SCE proposes to increase SERP spending from a 2008-2012 average of $5.9 million per year (2012$) to approximately $12 million per year. The increase would allow SCE to replace 339 "overstressed" circuit breakers and reduce the duty on 30 more through 2017.[145]

ORA considers SCE's forecast "ambitious" and proposes a slower rate of circuit breaker replacements, 45 per year. ORA accepts SCE's unit cost and proposes a cap of $7.415 million (nominal$) per year.[146]

In rebuttal, SCE claims that its forecast takes operational constraints into consideration and that it does not consider replacing 163 circuit breakers in 2014-2015 to be unrealistic.[147]

We agree with ORA that SCE has not demonstrated the need for the dramatic increase in replacements or the capacity to execute at this rate; however, we accept SCE's argument that some increase is warranted. Therefore, we adopt funding for 60 replacements per year in 2014-2015, or $9.887 million per year at the unit cost that SCE and ORA agree on.

[144] SCE-3V3 at 84-85.
[145] SCE-3V3 at 85-87.
[146] ORA-10 at 47-48.
[147] SCE-19V3 at 12.

	ORA	Adopted
Unit Cost	$ 0.165	$ 0.165
Units	45	60
Total	$ 7.415	$ 9.887

7.3.3.2. DSP Circuit Work

There are three types of projects in this category: 1) new circuits not associated with new substations, 2) miscellaneous non-circuit work, and 3) Circuit Load Reduction Program (CLRP). SCE notes that new circuit work is decreasing while the two latter types are increasing. Non-circuit work covers projects to transfer load from substations forecast to exceed loading criteria to other substations. CLRP covers work (other than adding circuits) to reduce load on existing circuits.[148]

ORA recommends reducing non-circuit work to $20 million per year and reducing CLRP to $14.454 million per year. ORA labels these amounts "generous" in comparison to five-year recorded averages.[149]

In rebuttal, SCE argues that its new planning process focuses on non-circuit and CLRP instead of constructing new circuits, suggesting that ORA overlooks the offsetting reductions to new DSP circuits. SCE shows that taken as a whole, this category is decreasing in its forecast, relative to past years.[150]

SCE's approach to reduce the emphasis on new circuits and instead focus on non-circuit work and CLRP appears reasonable. ORA's selective view of two components while ignoring cost reductions in the category as a whole is unreasonable. We find reasonable and adopt SCE's forecast for DSP circuit work.

7.3.3.3. Capacitor and Circuit Automation Programs

[148] SCE-3V3 at 87-94.
[149] ORA-10 at 50-51.
[150] SCE-19V3 at 14.

SCE's Capacitor Automation Program automates the controls for distribution capacitors and replaces obsolete control systems. SCE forecasts replacing 280 control systems per year at a cost of about $1.5 million.

SCE's Circuit Automation Program automates switches to better respond to unplanned outages by isolating faults more quickly and restoring service remotely. SCE forecasts automating approximately 160 switches per year at a cost around $7 million per year.[151]

ORA recommends 2013-specific reductions for each program, but accepts SCE's 2014-2015 forecasts.[152] Since SCE agrees to use 2013 recorded,[153] we do not give this recommendation further consideration. SCE's forecasts for these modest programs are adopted.

7.3.3.4. Uncontested Programs

SCE presents forecasts for Distribution Plant Betterment, Distribution VAR Plan, and Substation Load Information Monitoring. ORA supports SCE's forecasts.

Distribution Plant Betterment includes upgrading equipment to accommodate load growth. SCE forecasts expenditures slightly below recent historical averages for this program.

Distribution VAR Plan seeks to add capacitors (which supply VARs) to the distribution system, sufficient so that the entire distribution system will operate at unity power factor by 2016. Providing VARs on the distribution system reduces the need for higher voltage systems to meet these needs, and thus improves reliability. SCE forecasts small increases over recent historical expenditures.[154]

[151] SCE-3V3 at 97-100.
[152] ORA-10 at 50-52.
[153] SCE OB at 80.
[154] SCE-3V3 at 94-97.

Substation Load Information Monitoring installs equipment to remotely monitor load at substations to provide SCE better planning information and improve real-time operations. SCE plans to add this equipment to 20 substations per year from 2014 on at an annual cost just over $1 million.[155]

We find reasonable and approve SCE's forecasts for these uncontested programs.

7.3.4. Generator Interconnection Program

This program includes projects to interconnect new generators to SCE's transmission or distribution systems. Some or all of the costs for some projects are recovered from the generators, and recorded as Other Operating Revenue. None of the 19 projects in this category have CPUC jurisdictional costs greater than $1 million.[156] ORA initially recommended a $0.679 million disallowance in 2013, but later generally accepted 2013 recorded capital for the proceeding. ORA does not contest 2014-2015 expenditures.[157] SCE responds that it does not generally provide detailed discussion of projects under $1 million and that the Large Generator Interconnection Agreement for that project specifies the costs recovered from ratepayers. We adopt SCE's 2014-2015 forecast.

7.3.5. Added Facilities Projects

This category includes ratepayer costs to add facilities to meet customer requests for additional or non-standard service. Some projects are financed by the customer, others by SCE. Revenues recovered from the requesting customer are recovered as Other Operating Revenue, discussed in Section 7.11 below. Example projects include additional substations at the Port of Long Beach. SCE

[155] SCE-3V3 at 100-101.
[156] SCE-3V3 at 101-102.
[157] ORA-10 at 55-56.

forecasts $96.2 million in CPUC-jurisdictional costs during 2013-2017.[158] ORA agrees with SCE's forecast for 2014-2015, but raises concerns about 2016-2017.[159] We approve SCE's 2014-2015 forecast.

7.4. T&D – Infrastructure Replacement

SCE owns many pieces of infrastructure, and this infrastructure wears out over time. SCE considers infrastructure replacement, as discussed in this section, to generally refer to preemptively replacing infrastructure based on risk or reliability factors, as opposed to based on an inspection or in-service failure. SCE preemptively replaces infrastructure if the consequence of an in-service failure is high and inspections may not be able to accurately assess the risk of failure. Time-dependent failure rates suggest that the likelihood of failure increases as assets age. For a population of assets, the replacement rate will plateau at a "long-term steady-state replacement rate." SCE asserts that the average ages of several types of its infrastructure (e.g., poles, underground distribution transformers) are increasing, and correspondingly, the number of these assets that need to be replaced each year is growing.

SCE's total capital request for infrastructure replacement ranges from $279 million recorded in 2013[160] to $478 million in 2015 (nominal$). SCE was authorized $266 million in 2012 and recorded $167 million that year, noting that the timing of D.12-11-051 "had a significant impact on expenditures." SCE subdivides this request into several categories, discussed below.[161]

The key decision before the Commission in this section is how rapidly to replace infrastructure considering safety, reliability, and cost, in addition to other factors.

[158] SCE-3V3 at 102-107.
[159] ORA-10 at 56-57.
[160] SCE-77, Appendix A.
[161] SCE-03V4 at 1-13.

Our adopted capital expenditure forecast for infrastructure replacement is summarized in the following table (millions of nominal$).

Activity	Requested		Adopted	
	2014	2015	2014	2015
Worst Circuit Rehabilitation	85.086	112.961	85.086	104.272
Cable in Conduit Replacement	65.451	93.577	42.228	75.452
Testing-based Cable Life Extension	13.167	26.892	13.167	26.892
Underground Oil Switch Replacement and PMH-4 Switch Replacement	12.558	9.625	12.558	9.625
Capacitor Bank Replacement	13.048	13.325	13.048	13.325
Distribution Voltage Regulator	0.524	0.535	0.524	0.535
Automatic Recloser Replacement	2.388	2.438	2.388	2.438
Polychlorinated Biphenyl (PCB) Transformer Replacement	1.780	1.818	1.780	1.818
Transformer Bank Replacement	67.875	72.972	65.816	66.629
Circuit Breaker Replacement	29.259	31.430	24.036	24.375
4 kV Circuit Overload-Driven Cutovers	23.562	26.736	23.562	26.736
4kV Substation Elimination	41.889	85.556	41.889	85.556
Total	356.587	477.865	326.081	437.653

7.4.1. Underground Cable Programs

SCE discusses three infrastructure replacement programs for underground cable: WCR, CIC Replacement, and Testing-Based Cable Life Extension (TBCLE). These three programs manage SCE's approximately 50,179 miles of underground cable, including four different cable types. These different cable types were generally installed during different time periods, have different life expectancies, and different maintenance characteristics. SCE asserts that underground cable is unique in that it cannot be visually inspected, and argues therefore that there must be a preemptive replacement program to avoid unplanned outages. SCE relies on two primary metrics of reliability in its discussion: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Based on an engineering analysis of 20 circuits, SCE projects that without any preemptive cable replacement, SAIDI would increase by 61 minutes and SAIFI by 0.269 interruptions over the next 20 years. SCE believes it will inevitably experience some decline in reliability in coming years due to infrastructure aging. SCE concludes that replacing 570 conductor miles per year would be necessary to achieve today's level of reliability in 20 years. SCE proposes to replace 500 miles per year, divided between WCR and CIC.[162]

ORA suggests that the average customer would not notice the "minor" increase in SAIFI in 20 years of no underground cable replacement. ORA proposes a cable replacement rate of 400 miles per year in 2015 and beyond,[163] estimating the impact of this change on SAIFI to be 0.07 interruptions higher than SCE's proposed 500 miles per year. By ORA's calculation, this is a $50 million per year saving of capital expenditures, or close to $1 billion over 20 years. "ORA is confident" that ratepayers would be "happy" to accept these rate

[162] SCE-3V4.
[163] ORA proposes 350 miles in 2014.

savings for lower levels of reliability. ORA notes that the highest recorded level of replacement was 272 miles in 2009, and in 2012 only 177 miles were replaced, far lower than the levels proposed here.[164]

SCE cites Assembly Bill (AB) 66, which established Pub. Util. Code § 2774.1, as evidence of customers' dissatisfaction with current reliability levels. Further, SCE notes a decline in residential customer satisfaction as measured by J.D. Power surveys.

SCE also suggests that ORA's cost savings do not account for the cost of possible additional cable failures resulting from its lower proposed replacement rate. SCE claims that some of the cable will likely fail soon, and the replacement will be more expensive due to higher night labor costs and lost economies of scale from concurrently performing other projects. SCE also notes the increased inconvenience to customers of unplanned outages.[165]

ORA rejects this argument, on the grounds that the TBCLE program gives ORA confidence that cables allowed to remain are unlikely to fail in the near term. ORA recommends that future GRCs can revisit the issue if ORA's recommended replacement rate of 400 miles per year is too low for cable failure rates. ORA notes that it does not consider its forecast to be "etched in stone" and expects changes both in SCE's technology (e.g., the testing and replacement processes) and funding levels as these, and other, changes occur.[166]

CUE suggests that ORA ignores the impact on SAIDI of its proposal, noting that outages due to CIC tend to be longer than outages related to poles.[167]

[164] ORA-11 at 16-21.
[165] SCE-19V4 at 4-5.
[166] ORA OB at 83-86.
[167] CUE-2 at 10-12.

ORA rejects this argument, noting that the 69 minutes of outages CUE references, are spread over 20 years.[168]

TURN proposes that SCE should have increased its TBCLE program, and thus decreased the cost of the other two programs. TURN suggests that SCE should be able to achieve the same number of rehabilitated circuit miles by only actually replacing 50% of the miles of cable, thus achieving the same reliability benefits at lower cost. TURN quotes SCE's testimony from the 2012 GRC, stating an intent to reduce the amounts and costs of cable replacement through a testing program.[169]

SCE argues that TURN's view of the testing program is overly optimistic and states "with confidence" that testing will not double the effectiveness of replacement efforts. Among other factors, SCE argues that TURN does not consider that the percentage of CIC testing as "bad" varies from 50% to 20% and that replacement of mainline cable compared to CIC have very different reliability impacts. SCE argues that TURN incorrectly assumes that SCE has ignored efficiency gains from testing, but that SCE is actually counting on these gains to achieve the reliability demanded by customers in the long term. SCE states that it hopes to improve SAIDI and SAIFI through testing in combination with cable replacement. Further, SCE suggests that TURN's proposal to only replace cable tested as "bad" will delay WCR replacements by at least a year. TURN's proposal, SCE argues, would discourage the utility from adopting innovative approaches in the future.[170]

CUE notes that WCR and CIC replacement account for more than 75% of SCE's proposed capital expenditures to mitigate conductor failure and proposes

[168] ORA OB at 85.
[169] TURN-03 at 13-19.
[170] SCE-19V4 at 7-11.

to increase spending on these programs more than SCE. CUE claims that SCE's failure rate predictions are much lower than PG&E's, potentially compounding the increases in SAIDI and SAIFI in the near term. CUE proposes that SCE double its CIC replacement rate to a minimum of 350 miles per year, close to the rate that in-service CIC is reaching its mean time to failure. CUE's total replacement proposal (CIC and WCR) is 675 miles per year. At this level, CUE projects SAIDI and SAIFI to stay above 2012 levels until 2027 and 2024, respectively. CUE accepts SCE's unit costs.[171]

7.4.1.1. WCR Program

The WCR program began in 1997 as the Annual Circuit Review. WCR has two objectives: 1) minimize the impact of aging infrastructure on reliability, and 2) minimize the disparity in reliability between circuits. Thus, WCR focuses on circuits with high impacts on SAIDI and SAIFI. Typically, the "most risk-significant mainline cable" is replaced during rehabilitation, but other improvements may also be made.

SCE requests capital expenditures of $85.086 million in 2014 and $112.961 million in 2015 at unit costs of $0.340 million and $0.348 million, per mile respectively. This is an increase from $66.942 million recorded in 2012.

The WCR program aims to invest in circuits that will provide the largest reliability benefits. SCE notes that, in 2012, 7% of circuits were responsible for half of SAIDI. SCE selects circuits for further study based on five quantitative criteria and a variety of qualitative criteria, then designs projects to improve the selected circuits. Typically, less than 10% of the cable in a circuit is chosen for replacement based on factors including age, history of failure, and loading. In

[171] CUE-1 at 28-35.

addition to reliability benefits, SCE submits the WCR program has equity benefits by reducing disparities in reliability among customers.[172]

ORA recommends 2013 recorded (which is $16.411 million higher than SCE's forecast), accepts SCE's 2014 forecast, and proposes a reduction of $8.689 million for 2015. ORA accepts SCE's 2014-2015 unit costs. The reduction in 2015 is the result of ORA's proposed rate of 300 miles of cable replacement, compared to SCE's 325 miles.[173]

TURN proposes that the number of miles to be replaced should be reduced based on impacts of cable testing. TURN assumes that 50% of tested mainline cable will need to be replaced, based on SCE's analysis for testing CIC. From this assumption, TURN recommends replacing 125 miles in 2014 and 162.5 in 2015. As a secondary, "much more conservative" assumption, TURN suggests assuming a 65% failure rate based on the average of 50% and 79% (SCE's estimated threshold for cost-effectiveness of testing). This assumption suggests 161 miles in 2014 and 210 in 2015. TURN suggests that SCE's proposal "borders on being imprudent" given the inspection program. TURN accepts SCE's unit cost estimates.[174]

7.4.1.2. Cable in Conduit (CIC) Replacement Program

SCE began installing CIC in the 1960s and it now makes up approximately one fourth of SCE's cable population. CIC is made with integrated, thin-walled polypropylene tubing, and is not installed inside rigid ducts. CIC is difficult to replace because the cable resists being pulled out of the polypropylene tubing, especially if the tubing is damaged. SCE notes that a typical outage due to in-service CIC failure is over 20 hours. SCE forecasts $65.451 million in 2014 and

[172] SCE-3V4 at 14-28.
[173] ORA-11 at 21-23.
[174] TURN-3 at 16-22.

$93.577 million in 2015 on unit costs of $0.524 million and $0.535 million per mile, representing 125 and 175 miles, respectively. SCE notes that 175 miles is about 1% of the CIC population.

SCE describes a new process for removing old cable, and replacing new cable into the existing CIC ducting. If this method fails in a specific application, SCE will use traditional open cut trenching for replacement.

For 2013 and 2014, SCE will replace CIC based on historical circuit performance. For 2015 and beyond, SCE states that all CIC replaced will be selected based on testing. SCE anticipates a 50% failure rate from the testing.[175]

ORA accepts SCE's unit cost forecasts and proposes lower CIC replacement rates for 2014 and 2015, 100 miles each year. ORA also proposes to use 2013 recorded spending, which is lower than SCE's forecast. ORA notes that SCE's 2015 proposal represents greater than a 1,000% increase from 2012 miles replaced. ORA's proposed reductions are $13.051 million in 2014 and $40.077 million in 2015.[176]

TURN asserts neither SCE's unit count nor unit cost is reasonable. TURN recommends 87.5 miles per year, based on 50% of SCE's forecast and its testing rationale described above. For unit cost, TURN proposes a weighted average of traditional trenching costs and the new method described by SCE, but TURN proposes lower costs for each category. For traditional trenching, TURN recommends $0.593 million per mile (2012$) based on an average of 2009-2013, compared to SCE's $0.700 million per mile based on 2012. For the new method, TURN recommends $0.241 million per mile based on an average of recorded costs for this method through April 4, 2014, compared to SCE's $0.400 million

[175] SCE-3V4 at 28-36.
[176] ORA-11 at 23-26.

based on judgement. TURN recommends a weighted average of $0.360 million.[177] In its brief, TURN recalculates an average of $0.364 million.[178]

SCE rejects TURN's unit cost reduction, arguing that TURN bases its analysis on 7.8 miles of replacement, without considering the difficulty of replacement. SCE reiterates its claim that it is working to minimize unit costs, and its forecast reflects this.[179]

7.4.1.3. TBCLE Program

Under this program, a vendor will perform "partial discharge" testing on de-energized segments of underground primary cable. Segments rated "good" will be guaranteed by the vendor for 10 years against in-service failures; SCE will replace "bad" rated segments. FERC allows cable testing costs to be capitalized, with certain requirements; SCE asserts that this program meets the requirements and counts as capital expenditures.

SCE performed a pilot study in 2012 which it found successful. SCE found that a rapid pace of testing is possible, and that customers on typical circuits will only need to experience one planned outage for testing. SCE found that, on "poorly performing" circuits, about 50% of segments tested needed replacement. The total cost of testing is about $0.033 million per conductor mile. SCE's economic analysis concludes that testing is cost-effective, relative to replacing all CIC in the circuit. SCE plans to expand the program in 2015 to test mainline cable.[180]

TURN proposes that SCE should have begun testing 500 miles per year in 2014 and beyond. TURN calculates the impact of this as a $3.927 million (2012$) increase in 2014 and an $8.646 million decrease in 2015, relative to SCE's

[177] TURN-3 at 22-24.
[178] TURN OB at 62-63; TURN-43.
[179] SCE-19V4 at 12.
[180] SCE-3V4 at 37-41.

proposal. TURN argues that this rate allows SCE to "cost-effectively rehabilitate the conductor miles that its cable replacement models indicate." TURN recommends that we require a cost-benefit study of mainline cable testing in SCE's next GRC.[181]

7.4.1.4. Discussion

One of the key premises of preemptive infrastructure replacement is that the infrastructure in question cannot be effectively inspected or tested to evaluate its condition and likely remaining life. Underground cable presents obvious challenges for inspection, but SCE has developed new approaches for testing that initially appear successful and cost-effective, at least for CIC. SCE expresses optimism for similar results for testing mainline cable that could be replaced under WCR. The potential benefits of this testing program are significant. Logically, if the remaining life of underground cable can be effectively evaluated by testing, then only "bad" cable needs to be replaced, significantly reducing costs (both financial and otherwise) to customers associated with replacement in order to achieve equivalent reliability benefits. Under an effective testing paradigm, all underground cable may eventually be appropriately considered within the DIMP, discussed below in Section 7.6. To the extent that SCE proposes to replace untested cable (either mainline or CIC) in its next GRC, it must clearly explain why a testing-based replacement program is not more cost-effective; we anticipate efficiency improvements based on testing in this area.

We agree with TURN that SCE's request to dramatically increase the pace of cable replacement shortly before the benefits of this testing program are fully understood or realized is questionable. While we agree with SCE and CUE that

[181] TURN-3 at 26-27.

improving reliability through WCR and CIC replacement is an important goal, this goal must be balanced against customer costs. However, given the import of reliability and CUE's comparison to the rate of CIC reaching mean time to failure, TURN proposes reductions to the number of miles replaced that are too deep.

Accordingly, we adopt small reductions to SCE's forecast for miles of cable replaced. For WCR, we adopt ORA's proposal for number of miles replaced. For CIC, we adopt a forecast of 100 miles in 2014 and 175 miles in 2015. These small reductions relative to SCE's proposal reflect our belief that SCE can and should have done more to accelerate its use of testing. We note that we adopt SCE's full 2015 forecast for CIC because SCE states that all CIC replaced in that year will be cable that failed testing. We recognize that implementing such a change does take time, but the benefits to customers of reducing the amount of good cable replaced outweigh the benefits to customers of accelerated replacement of more total cable. SCE should direct more effort toward implementing testing, and reduce the likelihood of replacing cable unnecessarily.

Second, we adopt a reduction to CIC unit costs. TURN's point that unit costs should be based on data is valid. SCE's argument in rebuttal that the data TURN relied upon is inadequate to support TURN's proposed unit cost is vague. SCE suggests that the 7.8 miles of trenchless projects relied on by TURN is too small a sample, however, SCE presents no direct support for its own figure. We agree that this may be a small sample, but in the absence of a competing specific analysis, we find $0.300 million (2012$) per mile to be a reasonable forecast. For traditional trenching, SCE suggests that the multiple years of data employed by TURN are not representative, but again is not specific in its reasoning. In hearing, SCE's witness offered nothing more than anecdotal evidence and speculation that the small set of projects relied on by SCE is more representative

than the larger set evaluated by TURN.[182] Therefore, we find TURN's estimate of $0.610 million per mile to be a reasonable forecast. Using SCE's weighting factors, we calculate a weighted average of $0.403 million as shown below.

(Millions of 2012$)	Trenchless	Trenched
% of miles	33.33	66.67
$/mile	0.610	0.300
Weighted Avg.		0.403

For TBCLE, we find SCE's forecast reasonable. Our total forecast for the three programs is summarized below.

		2014		2015	
		Requested	Adopted	Requested	Adopted
WCR		85.086	85.086	112.961	104.272
	Miles	250	250	325	300
	$/mile	0.340	0.340	0.348	0.348
CIC		65.451	42.228	93.577	75.452
	Miles	125	100	175	175
	$/mile	0.524	0.422	0.535	0.431
TBCLE		13.167	13.167	26.892	26.892
Total ($millions)		163.704	140.481	233.430	206.616

7.4.2. A-Bank Transformer Replacement

SCE's Substation Infrastructure Replacement (SIR) program handles three types of transformer replacements: AA-bank, which are entirely FERC jurisdictional; A-bank, which transform 220 kV (transmission voltage) electricity to subtransmission voltages (115kV or 66kV); and B-bank, which convert subtransmission to distribution voltages. SCE asserts that SIR replaces transformers that are "approaching the end of their service lives, that contain parts which are known to be seriously problematic or are no longer available, or

[182] RT 677-681.

that can no longer be cost-effectively maintained." SIR also handles circuit breaker replacement, discussed in Section 7.4.3 below.[183]

SCE contends that in-service failures of A-bank transformers pose significant safety and reliability hazards. Inspections reduce the risk of in-service failures, but cannot prevent them completely. SCE argues that preemptive replacement is "prudent and responsible."

SCE claims that, in 2012, it began using formal engineering analysis to forecast the number of transformers to be replaced, and which specific transformers would be replaced. SCE's analysis suggests that the mean time to wear out for A-bank transformers is 37 years, compared to a current average age of 28 years in the 162 unit system. Based on the age distribution, SCE predicts five A-bank transformers will wear out each year from 2013 to 2022. SCE uses a "Health Index" (inversely proportional to probability of failure) to assess the physical condition of transformers. The Health Index, in addition to "Criticality," a measure of the consequence of an in-service failure, is used to determine the replacement schedule. This schedule is adjusted for expert judgement and to optimize with respect to other projects.

Some, but not all, A-bank transformers are FERC-jurisdictional. SCE's forecast is summarized in the following table (millions of nominal$):[184]

	Transformers			Unit Cost	CPUC Jurisdictional Forecast
	CPUC	FERC	Total		
2014	4	1	5	4.119	16.476
2015	5	0	5	4.228	21.141

TURN contends that SCE has a history of "either over-forecasting or under-delivering A-bank replacements" and that SCE's forecast should be

[183] SCE-3V4 at 68-71.
[184] SCE-3V4 at 68-76 and SCE-3V4A2.

reduced to 3.2 replacements per year based on the historical average replacement rate. In addition to historical replacement data, TURN relies on SCE testimony in past GRCs that SCE used analysis of the same types of physical information to forecast transformer replacements as SCE proposes to use in its Health Index. TURN concludes that this information does not accurately predict A-bank failure. Anecdotally, TURN notes that the only loss of load event driven by an internal A-bank failure was a transformer that had not been identified for replacement when it failed in 2013. Further, TURN points to SCE's claims in the 2012 GRC that a new monitoring program would increase A-bank life. TURN notes that SCE replaced three A-banks in 2013. TURN recommends funding for 2.2 A-bank replacements in 2014 and 3.2 in 2015, noting that the difference is because one of the 2014 replacements is FERC-jurisdictional.[185]

SCE proposes to read TURN's recommendation as three transformers in 2014 and four in 2015 because "obviously" it is impossible to replace a fraction of a transformer. Further, SCE argues that its "risk-informed approach" was new in the 2012 GRC and has resulted in significantly lower forecasts of A-bank replacements. Lastly, SCE sites SED's conclusion[186] that this approach "could serve as an example for other programs."[187]

As a foundational matter, although we agree with SCE that it must replace whole numbers of transformers, we agree with TURN[188] that ratemaking forecasts need not be restricted to whole numbers of transformers. Further, even if we accepted SCE's rounding premise, we see no justification for SCE's proposed creative rounding approach, e.g., why 3.2 should be rounded up to 4 rather than down to 3.

[185] TURN-3 and TURN-3A at 26-31.
[186] The report SCE cites was later admitted into evidence as exhibit ALJ-1.
[187] SCE-26V4 at 13-15.
[188] TURN OB at 67.

Substantively, we are swayed by TURN's argument that historical replacement rates are an important predictor of future replacements. On the other hand, we appreciate SCE's efforts to make risk-informed investments to avoid in-service transformer failures. Increasing the rate of A-bank replacements above the historical average is an appropriate step to reduce safety and reliability risks. Accordingly, we adopt SCE's recorded A-bank replacement spending for 2013 and 3.5 per year for CPUC-jurisdictional replacements in each of 2014 and 2015, for a total of nine A-bank replacements from 2013 to 2015. We accept SCE's uncontested unit costs. Our resulting forecast is shown below (millions of nominal$).

	CPUC A-bank	Unit Cost	Adopted Forecast
2014	3.5	4.119	14.417
2015	3.5	4.228	14.798

7.4.3. Distribution Circuit Breaker Replacement

The Distribution Circuit Breaker Replacement program identifies and replaces circuit breakers from 115kV to 2.4kV that are approaching end of service life, contain problematic or unavailable parts, or can no longer be maintained cost-effectively. SCE states that circuit breakers are critical for public safety and protecting other equipment in the event of a fault in the circuit. SCE describes engineering analysis (similar to A-bank transformers, above) to calculate a Health Index and select circuit breakers for replacement. SCE's analysis and forecast is summarized below. SCE's total forecast is $29.259 million in 2014 and $31.430 million in 2015.[189]

[189] SCE-3V4 at 84-91.

Voltage		115kV, 66kV	33kV to 2.4kV
Population		3,826	6,996
Average Age		18	32
Mean Time to Wear-out		48	
Forecast Replacements	2013	44	155
	2014	46	173
	2015	45	187
Unit Cost (Nominal $ x 1000)	2013	209	110
	2014	214	112
	2015	220	115

TURN contends that SCE's replacement rate is inadequately justified. TURN argues that SCE's forecast represents a total replacement rate, does not factor in the replacements done in the Circuit Breaker Inspection and Maintenance program (discussed in Section 7.6 below) which represents nearly twice the replacement rate here, and thus that SCE is proposing to replace circuit breakers much faster than its predicted wear-out rate. TURN observes that SCE's forecasted number of replacements for the lower voltage category is lower than its forecasted wear-out rate, but that the difference is not explained. TURN notes that both the inspection-based and preemptive replacement programs only replace breakers after field inspections and other analysis. TURN claims that there are few recent examples of circuit breaker failures with significant consequences. As a result, TURN recommends significantly lower replacement rates, as summarized below.[190]

		SCE		TURN	
		115kV, 66kV	33kV to 2.4kV	115kV, 66kV	33kV to 2.4kV
Forecast Replacements	2014	46	173	12	32
	2015	45	187	12	31

[190] TURN-3 at 31-36.

SCE argues that TURN's proposal misses the point of preemptive replacement. SCE claims that replacing circuit breakers can be complicated due to space constraints, need to replace related equipment, and other factors. In some cases, replacement can be a five-year process. Emergency replacements can lead to sub-optimal and more costly results. SCE asserts that TURN's proposal to limit the replacement rate to the forecast wear-out rate minus historic emergency replacement rate is bad for safety, reliability, and cost.[191] SCE also disputes the assumptions relied on by TURN in calculating its forecast of wear-out rate less other replacements.[192]

We agree with TURN that SCE has not adequately justified its proposed replacement rates, but we agree with SCE that some increase over historical rates is warranted. In D.12-11-051, we adopted a target of 175 circuit breaker replacements per year and find a small increase above this level reasonable for this GRC period. We adopt funding for 180 replacements per year during 2014 and 2015. While this number is below SCE's forecast wear-out rate, it is considerably higher than TURN's calculation of wear-out less other replacements, thus allowing SCE to make progress toward the goal of reducing in-service failures. We adopt SCE's uncontested unit costs. In the next GRC, SCE should provide analysis of the preemptive replacements in combination with other types of replacements. Our adopted forecast is summarized below (millions of nominal$).

	Adopted Replacements		Adopted Forecast, Total
	115kV, 66kV	33kV to 2.4kV	
2014	38	142	24.036
2015	35	145	24.375

[191] SCE-19V4 at 17-18.
[192] SCE OB at 89-90.

7.4.4. Uncontested Infrastructure Replacement Programs

7.4.4.1. B-bank Transformers

SCE makes the same safety and reliability arguments in favor of its B-bank transformer replacements as summarized above for A-bank replacements. SCE also describes the same type of engineering analysis to calculate a Health Index and select transformers for replacement. SCE's analysis suggests that the mean time to wear out for B-bank transformers is 57 years, compared to a current average age of 40 years in the 2,596 unit system. SCE originally forecast replacing 30 transformers in 2013, 42 in 2014, and 33 in 2015. These totals are made up of five different voltage classes of transformers, ranging from 115kV with a 2015 unit cost of $1.730 million to 12kV with a 2015 unit cost of $0.598 million.[193] ORA proposes to use SCE's recorded 2013 value and to reduce the 2014 forecast to 30 transformers.[194] In rebuttal, SCE accepts ORA's forecast, citing resource constraints in 2014.[195] We adopt ORA's uncontested forecast as shown below (millions of nominal$).

2014	2015
29.454	33.529

7.4.4.2. 4 kV Circuit Replacement

SCE has approximately 4,600 distribution circuits, mostly operating at modern standard voltages. However, SCE has 1,100 circuits and 211 substations operating at 4kV or lower voltages. SCE argues that these circuits are limited, inefficient, inflexible, and full of obsolete equipment. SCE has two programs to eliminate these circuits: 4kV Circuit Overload-Driven Cutover reduces the size of

[193] SCE-3V4 at 76-82.
[194] ORA-11 at 26-29.
[195] SCE-19V4 at 16.

4kV circuits by transferring load to other circuits, and 4kV Substation Elimination transfers circuits to higher voltage substations. In D.12-11-051,[196] we encouraged SCE to ensure these programs are coordinated. SCE has indicated that many projects planned by these programs are coordinated. We find reasonable and adopt SCE's uncontested forecasts as summarized below (millions of nominal $).[197]

	Circuit Overload-Driven Cutovers	Substation Elimination
2014	23.562	41.889
2015	26.736	85.556

7.4.4.3. Other Uncontested Infrastructure Replacement Programs

The Commission has reviewed SCE's other uncontested infrastructure replacement programs including: PMH-4 switches, underground oil switches, distribution voltage regulators, automatic reclosers, and Polychlorinated Biphenyl (PCB) transformers. We find SCE's forecasts for these programs reasonable.

7.5. T&D – Customer-Driven Programs and Distribution Construction

SCE pursues many types of work in response to customer requests and to build out its distribution system, including: new service connections, undergrounding facilities in accordance with Rule 20, relocating or modifying service to meet customer requests, and prefabrication and purchase of materials and equipment for construction activities.[198]

The primary driver of the expenses in this chapter is the forecast of gross meter sets, discussed below in Section 16. The parties' different meter forecasts

[196] D.12-11-051 at 159.
[197] SCE-3V4.
[198] SCE-19V5 at 1.

represent the key difference between their positions. We do not review those positions here, but simply apply our adopted meter forecast to the methods used by the parties to calculate an adopted forecast for most categories of costs. We focus our attention in this section on the remaining disputed issues.

7.5.1. O&M

SCE's total O&M forecast is $16.008 million (2012$) in Accounts 586.140, 588.140, and 588.271 (a credit).

For Account 586.140, Meter Installation and Replacements, SCE uses the 2012 recorded cost per meter of $77, noting that smart meters will be the norm in the future. SCE levelized its 2015-2017 forecasts to develop its test year forecast.[199] ORA accepts SCE's unit cost, but opposes the levelized forecast, claiming that the attrition mechanism provides for appropriate increases.[200] SCE argues that the attrition mechanism does not assume increasing levels of work and submits that the increasing numbers of meter sets in the forecast necessitates the levelization approach in order to recover SCE's costs. SCE claims that we have adopted the levelized approach in the past, but the citation provided does not support the claim.[201] We accept SCE's point that the actual number of meters installed in the post-test years is forecast to be considerably higher than in 2015, and accept SCE's proposal to adopt a levelized forecast.

SCE and ORA have the same dispute over levelizing the Distribution Line Rents portion of Account 588.140. SCE notes that its rents to governmental landowners are contractually subject to 1.9% escalation per year.[202] We have modified the Results of Operations model used in preparation of this decision so that O&M costs categorized as "other" in this Account (and the analogous

[199] SCE-3V5 at 7-9.
[200] ORA-8 at 18-20.
[201] SCE-19V3 at 4.
[202] SCE-19V3 at 5-7.

Account for Transmission discussed in Section 7.9.1.1) are not escalated. Therefore, we accept SCE's proposal to levelize this expense and adopt SCE's forecast.

ORA also disputes SCE's forecast of Miscellaneous Construction Inspection Expenses in 588.140 based on applying SCE's method to ORA's capital forecast instead of SCE's.[203] There is no dispute about methods here; therefore, we apply SCE's method to our adopted forecast.

SCE's forecasts for other elements of 588.140 and all of Account 588.271 are uncontested and are approved.

Our total adopted O&M forecast, based on the meter set forecast discussed below, is shown in the following table (millions of 2012$).

Category	Labor/Non-Labor Ratio[204]	2015 Expenses		
		SCE	Adopted	Δ
586.140				
Meter Installations and Replacements	55/45	$11.492	$11.378	$0.114
Labor Allocation of Total		$6.286	$6.258	$0.028
Non-Labor Allocation of Total		$5.206	$5.120	$0.086
588.140				
Misc. Construction Inspection Expenses	77/23	$1.154	$0.869	$0.285
Facility Inventory Mapping	83/17	$0.782	$0.782	$0
Field Accounting	94/6	$1.799	$1.799	$0
Stand-by Time	74/26	$0.707	$0.707	$0
Distribution Line Rents	100% Other	$1.943	$1.943	$0
Shop Services and Instrumentation	8/92	$0.651	$0.651	$0

[203] ORA-8 at 21-23.
[204] SCE-3V5.

Division (SSID) Operating Expenses				
Wireless Technology Services	35/65	$0.246	$0.246	$0
Total		$7.282	$6.997	$0.285
Labor Allocation of Total		$3.888	$3.671	$0.217
Non-Labor Allocation of Total		$1.451	$1.383	$0.068
Other Allocation of Total		$1.943	$1.943	$0
588.271				
Productivity Benefits	100% Non-Labor	($2.766)	($2.766)	$0
Grand Total		**$16.005**	**$15.609**	**$0.396**

7.5.2. Capital

As noted above, different meter forecasts are a key difference between parties. ORA states that it has reviewed SCE's forecasts and supports many of the component forecasts. Therefore, for many components, the only difference is the meter forecasts. TURN's view is similar, although TURN disputes more issues on grounds other than the meter forecast. We have also reviewed the component forecasts that are undisputed, aside from number of meters, and find SCE's forecasts reasonable. Therefore, we discuss in detail only the otherwise disputed components.

TURN claims that SCE accepts approximately $90 million of reductions proposed by TURN to its 2014-2015 capital forecast.[205] We note that this is an exaggeration as there was no material dispute between the parties on the methods used for two of the four issues that TURN cites.

Our adopted capital forecast for contested issues is summarized below.

[205] TURN OB at 73-75 and JCE-3 at 143-150.

Line #	Category	Capital Expenditures					
		2014 2/			2015 3/		
		SCE 4/	Adopted	Δ	SCE 4/	Adopted	Δ
1	Residential Service Connection Costs (Nominal $)	$30,008	$24,063	$5,945	$39,187	$35,961	$3,226
2	Residential Line Extension Costs (Nominal $)	$28,542	$21,844	$6,697	$38,617	$34,928	$3,689
3	Residential Tract Development Costs (Nominal $)	$81,260	$73,617	$7,644	$91,217	$92,480	($1,263)
4	Residential Backbone Development Costs (Nominal $)	$16,143	$14,624	$1,519	$18,121	$18,372	($251)
	Total Residential	$155,953	$134,149	$21,804	$187,141	$181,740	$5,401
5	Commercial Service Connection Costs (Nominal $)	$19,935	$17,195	$2,740	$26,780	$22,002	$4,778
6	Commercial Line Extension Costs (Nominal $)	$37,868	$34,436	$3,432	$50,977	$44,064	$6,913
7	Commercial Tract Development Costs (Nominal $)	$13,150	$11,343	$1,807	$17,719	$14,514	$3,205
	Total Commercial	$70,953	$62,974	$7,979	$95,476	$80,579	$14,897
8	Agricultural Service Connection Costs (Nominal $)	$1,324	$842	$481	$1,367	$868	$499
9	Agricultural Line Extension Costs (Nominal $)	$2,731	$3,151	($420)	$2,789	$3,247	($458)
	Total Agricultural	$4,055	$3,993	$61	$4,156	$4,115	$41
10	Streetlight Service Installation Costs (Nominal $)	$30,575	$23,464	$7,112	$41,403	$37,517	$3,886
11	Rule 20A Costs (Nominal $)	$22,575	$22,575	$0	$23,289	$23,289	$0

12	Rule 20B Costs (Nominal $)	$34,182	$27,526	$6,656	$43,206	$38,852	$4,354
13	Rule 20C Costs (Nominal $)	$10,165	$8,222	$1,943	$12,930	$11,605	$1,325
14	Prefabrications (Nominal $)	$28,516	$26,220	$2,297	$28,454	$26,032	$2,422
15	Distribution Transformers (Nominal $)	$88,073	$79,131	$8,942	$97,897	$94,066	$3,831
	Total	$440,992	$384,259	$56,733	$533,952	$497,795	$36,158
	NOTES:						
	2/ Lines 1 through 10 for SCE's forecast come from Exhibit SCE-19, Vol. 5, Table I-14, page 14. For Line 11, SCE accepts ORA's forecast, as noted on page 16. For Lines 12 and 13,						
	SCE accepts a total expenditure of $44.3 million (see page 18) allocated between 20B and 20C using SCE's 77/23 ratio. Adopted forecasts are derived using the methodologies discussed in the PD.						
	3/ Lines 1 through 10 for SCE's forecast come from Exhibit SCE-19, Vol. 5, Table I-14, page 14. For Line 11, SCE accepts ORA's forecast, as noted on page 16. For Lines 12 and 13,						
	SCE accepts a total expenditure of $56.1 million (see page 18) allocated between 20B and 20C using SCE's 77/23 ratio. Adopted forecasts are derived using the methodologies discussed in the PD.						
	4/ Lines 1 through 10 appear as Constant 2012 dollars in Exhibit SCE-19, Vol. 5, Table I-14, page 14. Conversions to Nominal dollars are made using a factor of 1.04721 for 2014 and 1.06945 for 2015.						

7.5.2.1. Customer Meter Connections

SCE installs service connections, line extensions, and tract and backbone development for residential customers, as well as connections and line extensions to commercial, industrial, and agricultural customers and street light installations. There are ten line item forecasts discussed in this category. SCE forecasts significant growth in expenditures in this area between 2012 and 2017. Forecasts can be summarized by the following equation:

Capital = Meters * Unit Count per Meter * Cost per Unit

Unit counts can be the number of new connections or feet of line extension, for example. SCE generally uses five-year averages of historical data to develop its unit costs, with the exception of agricultural service connections for which SCE uses a four-year average. To develop its unit count forecasts, SCE typically uses historical data and statistical analysis of the relation of number of units to the number of new meters.[206]

TURN proposes to use a five-year weighted average to forecast unit costs, as opposed to SCE's five-year arithmetic average, resulting in some higher and some lower forecasts relative to SCE.[207] SCE notes that the difference between these unit cost forecasts is small and requests that one approach be used consistently for all ten forecasts.[208] TURN agrees to this clarification.[209] We agree with SCE that the difference is small, but find that, all else equal, a weighted average is likely to be less influenced by outliers and is preferable to an

[206] SCE-3V5 at 21-53.
[207] TURN-5 at 49.
[208] SCE-19V5 at 13.
[209] TURN OB at 74.

arithmetic average. Therefore, we adopt TURN's recommended five-year weighted average approach.[210]

TURN proposes different equations to forecast the unit counts for several of the ten line item forecasts. TURN criticizes SCE's statistical models on various grounds, including: use of independent variables that are not statistically significant, overly complex regressions for the sample size, and unexplained discontinuities.[211] TURN includes excerpts from SCE's workpapers as an attachment to its testimony.[212] SCE states that different models can be used, and does not specifically rebut TURN's proposals.[213] We generally find that TURN's critiques have merit and that TURN's models are more reasonable. Therefore, we adopt TURN's models for calculating unit counts, based on our adopted meters forecast.

7.5.2.2. Underground Conversions – Rule 20A

Tariff Rule 20A allocates funding to government agencies within SCE's territory to underground existing distribution lines. Each government agency may select which locations it wishes to convert to underground. Thus, SCE states that the municipalities are the main drivers of Rule 20A spending. SCE notes that since 2010, government agencies have approved $62 million of Rule 20A projects and have considered $119 million more. SCE requests $31.8 million (2012$) per year, a slight increase from 2012 authorized.[214]

[210] Costs in the "TURN Unit Costs" column of Table I-12, pg. 12 of SCE-19V5 are used for most categories. For the agricultural categories for which no TURN Unit Cost is shown and for Commercial/Industrial Line Extensions, we calculate five year weighted average Unit Costs based on the data provided in SCE-3V5.
[211] TURN-5 at 50-59.
[212] TURN-6, attachment 8.
[213] SCE-19V5 at 12-13.
[214] SCE-3V5 at 56-59.

ORA recommends a $10.818 million (nominal$) "penalty" reduction to SCE's 2014-2015 forecasts to correct for SCE underspending relative to authorized during 2009-2013. In its analysis, ORA cites our decision in SCE's last GRC that discussed historic underspending as well as the safety, reliability, and aesthetic value of undergrounding, and encouraged SCE to "fully support" undergrounding.[215] As a result of SCE's underspending in light of this direction, ORA concludes that its proposed penalty is reasonable.[216]

SCE rejects ORA's logic that a penalty is appropriate and notes that SCE is not authorized to spend Rule 20A funds without requests from the government agencies. Nevertheless, SCE accepts ORA's forecast.[217] We find reasonable and approve ORA's uncontested forecast.

7.5.2.3. Underground Conversions – Rules 20B and 20C

Under Rules 20B and 20C, a site-specific undergrounding conversion is made at the request of an applicant. SCE finds a strong correlation between conversions and residential line extensions.[218] In addition to different meter forecasts, ORA calculates a lower unit cost than SCE.[219] SCE accepts ORA's calculated unit cost.[220] TURN proposes to lower the forecast of miles of undergrounding per meter, based on its lower forecast of residential line extensions per meter, which we adopted in Section 7.5.2.1. above. TURN also calculates a different unit cost based on a five-year weighted average.[221] SCE accepts TURN's approach and unit cost.[222] Accordingly, we adopt TURN's unit

[215] See D.12-11-051 at 165-166.
[216] ORA-11 at 60-63.
[217] SCE-19V5 at 16.
[218] SCE-3V5 at 61-63.
[219] ORA-11 at 66-67.
[220] SCE-19V5 at 17.
[221] TURN-5 at 62-63.
[222] SCE-19V5 at 17-18.

cost method and method for calculating the unit count. Our calculation of the unit cost reaches a different result than that presented by TURN and SCE; we apply the unit cost as calculated below (000s of 2012$).

Category	Recorded				
	2008	2009	2010	2011	2012
	(a)	(b)	(c)	(d)	(e)
Recorded Rule 20B Installation Costs (2012 Constant $)	$27,794	$28,364	$16,211	$15,632	$12,657
Recorded Rule 20C Installation Costs (2012 Constant $)	$11,833	$9,649	$5,654	$6,296	$7,028
Total Rule 20B & 20C Installation Costs (2012 Constant $)	$39,627	$38,013	$21,865	$21,928	$19,685
Total Miles of Service Conductors Installed	167	151	89	95	71
5-Year Wtd. Average Unit Cost (Constant $)	$246.56				

7.5.2.4. Other Issues

The forecasts for transformers and prefabrication are uncontested as to the method of derivation, but depend on other elements of the distribution capital forecast. In calculating the approved level of capital expenditures for these customer-driven programs, we apply the methods agreed upon by the parties to the relevant elements of our adopted T&D forecast. The adopted values are shown in the summary table at the beginning of Section 7.5.2.

7.6. T&D – Distribution Inspection and Maintenance

This section addresses SCE's expenditures to implement its Distribution Inspection and Maintenance Program (DIMP). SCE is subject to a variety of CPUC regulations, including General Orders (GOs) 95, 128, and 165, and DIMP manages SCE's compliance with these requirements. SCE's DIMP was created in 2008 and has changed over time. DIMP prioritizes work projects according to urgency, but all identified maintenance is carried out when maintenance work is scheduled at a pole or structure. During TY 2015, SCE forecasts $189.474 million

(2012$) in O&M and $462 million (nominal$) in capital expenditures.[223] TURN and ORA forecast significantly lower values.

7.6.1. Underground Structure Rehabilitation Program

This program inspects, repairs, and replaces underground structures. The primary underground structures are vaults, which typically contain energized equipment, and manholes, which typically contain spliced cable, but not equipment. GO 165 requires inspections of underground equipment, but SCE also inspects underground structures without equipment. SCE's inspectors perform Underground Detailed Inspections (UDI), and structural engineers perform follow-up Field Investigations, if warranted. The Field Investigation determines whether the failing structure will be repaired or replaced. SCE bases its forecasts on a mix of historic and expected inspection, investigation, failure, replacement, and repair rates. For example, SCE expects the 2012 recorded rate of inspected structures found to be deteriorated (7.76%) to decline to 4%. Historically, 39% of vaults that receive a field investigation have resulted in replacements, with repairs to the remaining 61%.[224] SCE explains that underground structure failures, one of the ten risk statements SCE identified in its supplemental testimony, are unpredictable and a hazard both to employees and the public. A failure may lead to injury, property damage or outage. For example, violent equipment failure in the confined space of a vault poses substantial danger when the energy released by the equipment failure damages the vault structure, causing surface cave-ins, and ejection of vault lids and debris. These types of failures can result in injuries to pedestrians and traffic accidents. Similarly, the risk to workers is greatly increased if a vault structure has deteriorated and/or water has seeped into a vault. SCE states that structures

[223] SCE OB at 93-94 and SCE-3V6P1(A) at 1-4.
[224] SCE-3V6P1 at 27-28.

without equipment pose similar risks to structures with equipment.[225] SCE's total O&M forecast of $22.834 million is summarized below (2012$, millions):[226]

Account	583.120	583.120	593.120
Activity	Underground Detail Inspection (UDI)	Field Investigations	Underground Structures Repair and Shoring
Labor	4.389	0.134	1.669
Non-Labor	1.036	0.642	14.964
Total	5.425	0.776	16.633
Basis	Forecast UDI * LYR unit cost	Forecast investigations * unit cost	Repairs and shorings * unit cost, average of 2015-2017

For capital, SCE forecasts replacing approximately 200 vaults per year at a cost of $300,000 each and up to 20 manholes per year at $150,000 each. The total capital forecast is (nominal$, millions):[227]

2014	**2015**
70.687	72.188

ORA recommends $6.963 million for O&M in Account 593.120 based on LRY, noting that this is the highest recorded year and claiming SCE has not justified the 139% proposed increase. ORA does not address Account 583.120.[228] For capital, ORA recommends that 2013 recorded ($43.2 million, nominal) be allowed, and adjusted for inflation for each of 2014 and 2015. ORA claims that SCE's forecast assumes that certain vaults and manholes will be unnecessarily inspected multiple times in 2012-17, suggesting that SCE's forecast number of replacements is too high. Further, ORA argues that SCE's reliance on 2012 unit replacement costs is inappropriate because economies of scale will decrease unit

[225] SCE-15 at 32-34.
[226] SCE-3V6P1 at 13, 27-33, and 54-55.
[227] SCE-3V6P1 at 34-35.
[228] ORA-9 at 19-21.

costs. Anecdotally, ORA claims the engineering report for a specific replaced vault recommended repair rather than replacement.[229]

TURN devotes an entire exhibit to this program. TURN notes that SCE proposes a ten-fold increase in capital expenditures relative to the 2008-2012 average and argues that SCE has not justified this increase. TURN's primary critique of SCE's proposal is that SCE has not adequately justified the proposed 7.8% failure rate assumption, noting that the historical experience of this high failure rate is limited to 2012 and that previous years were much lower. TURN hypothesizes that a change in the failure criteria, unexplained and unacknowledged by SCE, may drive the change. TURN also notes that the proportion of replacements among failing structures is increasing (39%, up from 25% in the 2012 GRC). TURN accepts SCE's unit cost forecasts. TURN proposes $7.807 million in O&M (Account 593.120, Underground Structures Repair and Shoring) to repair up to 150 vaults per year and up to 137 manholes[230] and $33 million in capital to replace 100 vaults for the test year.[231]

In rebuttal, SCE claims that the increase in failure rate from 2009 to 2012 was driven by the program reaching maturity and that 2013 recorded data is consistent with SCE's forecast. Further, SCE calculates that the ORA and TURN proposals would not allow for SCE to complete replacements identified by the end of 2013 during the 2014 to 2017 time period. SCE disagrees with ORA's prediction that economies of scale will drive down unit costs, citing the complexity of the projects.[232]

We			

[229] ORA-12 at 18-19.
[230] TURN's manhole repair forecast is 53 in 2015, and 137 in each of the attrition years. The dollar value is normalized.
[231] TURN-16 at 18-19.
[232] SCE-19V6P1 at 16-24.

adopt a limited reduction to SCE's request. We agree with TURN that SCE's explanation of the increased failure rate is inadequate to justify the increase in costs. SCE has provided little detail on what changes occurred leading up to 2012 that would explain the increase in failure rate beyond the vague claim of the program reaching			

maturity. The specifically identified changes (structural engineers performing Field Investigations, inspecting structures without equipment) are unlikely to explain the entire increase. We also agree with ORA that it is reasonable to anticipate some reduction in unit costs for repair and replacement, but the record			

in this proceeding does not allow us to quantify that reduction. Nevertheless, we take SCE's point that there is a considerable queue of structures identified for replacement. Allowing these replacement projects to remain uncompleted indefinitely poses a safety risk that must be balanced against the costs of the program.			

Accordingly, we adopt small reductions to SCE's forecast. We accept SCE's forecast for the UDI and Field Investigation components of Account 583.120 and reduce SCE's forecasts for the underground structure repair portion of Account 593.120 and capital expenditures for 2014 and 2015 by 20% each. This reduction			

anticipates some decrease in the failure rate and gives SCE an incentive to achieve unit cost reductions. At SCE's proposed unit costs, this level of capital funding allows SCE to replace all vaults and manholes currently in the queue within approximately 3.4 years, if no future failures were			

identified.[233]			

This is a very large increase in funding for this program, consistent with our focus on safety; however, we decline to adopt SCE's full requested increase based on the limited historical data available. We anticipate the need for this high level of spending to be short in duration. If failure rates and/or unit repair and replacement costs have not declined when SCE is preparing its next GRC showing, SCE should present considerably more detail explaining these factors to justify further high costs of this program.

For O&M (millions of 2012$), we approve:

	Requested		Approved	
Account	583.120	593.120	583.120	593.120
Labor	4.523	1.669	4.523	1.335
Non-Labor	1.678	14.964	1.678	11.971
Total	6.201	16.633	6.201	13.306

For capital expenditures, we approve (millions of nominal $):

	2014	2015
Requested/Recorded	$70.687	$72.188
Approved	$56.550	$57.750

7.6.2. Distribution Maintenance O&M and Capital

Distribution maintenance includes labor, materials and other costs resulting from inspections, emergencies, and other normal business. Storm events and other claims are excluded.

233 ⊥

‼Unit Cost‼Queue‼Total Cost ($millions)‼↕ Vault‼0.3‼588‼176.400‼↕ Manhole‼ 0.15‼52‼7.800‼↕ Total‼ ‼640‼184.200‼↕ Divided by $54 million /year‼3.4 years‼↕

SCE notes an upward trend in distribution maintenance O&M costs, and therefore recommends an O&M forecast based on LRY. SCE's forecast includes portions of Accounts 593.120 and 594.120, as shown below (2012$, millions).[234] SCE's O&M forecast is uncontested, we find it reasonable, and it is approved.

Account	593.120	594.120	Total
Labor	21.376	13.949	35.325
Non-Labor	29.503	13.505	43.008
Total	50.879	27.454	78.333

SCE also bases its capital expenditures forecast on LRY ($255.713 million nominal$ in 2015), adjusted for inflation for the same reasons. SCE forecasts additional capital expenditures $15 million above this level for 2013 to complete safety and reliability projects identified at the local level.[235] SCE stipulated to using 2013 recorded rather than this forecast.[236] ORA stipulated to SCE's forecast, including 2013 recorded.[237] We adopt this uncontested forecast (millions of nominal$).

2014	2015
250.396	255.713

7.6.3. Inspection and Maintenance O&M

7.6.3.1. FERC Account 583.120

SCE's total forecast for this account is $23.173 million, up from $17 million recorded in 2012. This forecast includes seven elements.[238] ORA proposes reductions to two elements in SCE's forecast for this account. TURN forecasts a higher Joint Pole Credit than SCE. For elements not discussed below, SCE's

[234] SCE-3V6P1 at 14-16.
[235] SCE-3V6P1 at 16-19.
[236] SCE-49.
[237] ORA-57R.
[238] SCE-3V6P1 at 54.

forecast is uncontested and is adopted. A summary of the adopted forecast is shown below (2012$, millions).

FERC Account 583.120	Requested	Adjustments	Adopted
Labor	13.053		13.053
Non-Labor	10.120	-1.913	8.207
Total	23.173	-1.913	21.260

7.6.3.1.1. Overhead Detail Inspections (ODI)

The purpose of an ODI is to evaluate SCE's equipment for hazardous conditions, determine corrective action, perform minor repairs, and document findings. GO 165 requires inspections of overhead equipment every five years. Beginning in 2013, SCE requires inspectors to gain access to every pole to complete the inspection. SCE believes this change improves safety. SCE forecasts $7.750 million for this program, or $29 per pole inspected. The cost per pole increased "due to changes in work methods and accounting practices" in 2012; further increases in 2013 are driven by the new access requirement.[239]

ORA bases its forecast of $5.239 million on 2012 recorded costs, noting that this is the highest recorded year and claiming SCE's requested 48% increase is not justified. ORA claims that SCE has provided no detail on the costs associated with reaching backyard poles.[240]

SCE argues that the difficult-to-access poles activity is a new program that is not included in recorded costs, and that it has experience with similar programs. SCE also points to its workpapers, which include a forecast of the difficult-to-access poles.[241]

[239] SCE-3V6P1 at 10-12; SCE-19V6P1 at 3-5.
[240] ORA-9 at 12-13.
[241] SCE-19V6P1 at 6-7.

SCE's new emphasis on accessing all poles is appropriate, and SCE has put forward a credible estimate of the additional cost to reach difficult-to-access poles. We find SCE's forecast reasonable and adopt it (2012$, millions).

Labor	4,295
Non-Labor	3,455
Total	7,750

7.6.3.1.2. Distribution Intrusive Pole Inspections

GO 165 requires a continuing 20-year cycle of intrusive[242] pole inspections for all poles over 25 years old; SCE completed its first cycle in 2007. In 2009, SCE began a transition to a grid-based inspection program in order to increase consistency in activities year to year and improve efficiency. In 2009, SCE also began a transition to a ten-year inspection cycle, as later approved in the 2012 GRC;[243] SCE performs visual inspections on poles that will not be due for an intrusive inspection until the next cycle. This ten-year cycle requires that about 130,000 poles (10% of the total) be inspected each year. SCE argues that the number of inspections was too low in 2011-2012, and plans to inspect more poles in 2013-2015. Since contractors perform the inspections, most costs are non-labor; contract rates vary with the type of inspection. SCE bases its forecast on number of poles, mix of inspection types, the rate for each type, and the 2012 labor to non-labor ratio. SCE's total forecast is $7.000 million, at $47 per inspection.[244]

ORA forecasts $5.502 million, arguing SCE's requested 123% increase is not justified. ORA contends that SCE has not explained why it did not spend as much as authorized in some prior years. ORA claims that its forecast is more

[242] Meaning that the internal integrity of the pole is evaluated.
[243] D.12-11-051 at 180.
[244] SCE-3V6P1 at 37-40.

than 2012 recorded and that SCE "should also have embedded funding that can be reallocated back to this account."[245]

SCE claims that it "caught back up" on inspections in 2013, completing 170,613, and has approximately maintained the target ten-year average (2009-2013 average of 127,292).

SCE claims that ORA's forecast is based on a four-year average (2009-2012), and thus represents only 116,462 inspections per year -- not enough to maintain the ten-year cycle. SCE further contends that inspecting fewer poles will increase unit costs because SCE would still be required to inspect many poles for compliance, outside of the grid areas funded by ORA's proposal. SCE concludes that under ORA's proposal, 112,110 poles would be inspected at a unity cost of $49.[246]

We support SCE's ten-year, grid-based cycle as a reasonable approach to reduce risk and reduce unit costs. In order for SCE to complete the transition to grid-based inspections, it is necessary to inspect more poles than would be possible under ORA's forecast. We adopt SCE's forecast.

7.6.3.1.3. Joint Pole Expenses and Credits

The Joint Pole Organization (JPO) manages the poles that SCE shares with other utilities. SCE forecasts $3.287 million in expenses for the JPO based on LRY with 90% of that to labor.[247] No party contests this forecast and we find it reasonable.

JPO also receives expense credits from other utilities based on three activities: inspections, maintenance, and penalties for unauthorized use of SCE-owned poles. SCE's total forecast of credits is $2.087 million, 100%

[245] ORA-9 at 15-17.
[246] SCE-19V6P1 at 31-32.
[247] SCE-03V6P1A at 47-48.

non-labor, based on: a 5YA of unit credits for inspections, LRY for maintenance, and LRY for penalty credits.[248]

TURN argues that JPO credits are too low. TURN argues that SCE's credit per inspection ($8) should be $16 (=$47/pole*50% cost share *70% portion of joint poles), and therefore recommends an increase of $1.3 million for inspection credits. Similarly, TURN contends that maintenance credits related to vegetation clearing are too low, and calculates $1.5 million/year (=118,084 poles x $52/pole * 50%/2 years). Further, TURN claims that SCE is under-collecting credits from joint owners and suggests that credits flow through the Pole Replacement Program Balancing Account and that additional reporting on credits should be required. Finally, TURN proposes that forecast penalties should be quadrupled to $1.5 million on the grounds that SCE's planned maintenance, inspection, and replacement activities in this GRC cycle will reveal more unauthorized pole attachments. TURN's proposed increases total $3.4 million.[249]

SCE claims TURN's assumptions are incorrect. First, SCE clarifies that 70% of poles are joint use, not necessarily jointly owned and that renters do not pay for inspections and that TURN's assumptions do not accurately reflect agreed payments among pole owners. SCE argues that TURN's inference that SCE under-collects for inspections is incorrect, noting that the number of invoices is not the same as the number of poles billed. SCE disputes TURN's assumption that vegetation is cleared every two years. SCE argues there is no link between pole replacements and penalty credits. Generally, SCE argues its forecasts based on recorded data are more reasonable than TURN's assumptions and calculations.[250]

[248] SCE-03V6P1A at 48-50.
[249] TURN-20 at 35-40.
[250] SCE-19V6P1 at 34-36.

While SCE has challenged TURN's assumptions, it has not proposed clear alternatives, such as for the portion of jointly owned poles. Clearly identifying correct numbers for these assumptions would advance SCE's case and demonstrate that it is not under-collecting. Further, SCE overstates the connection between TURN's proposed penalty increase and pole replacements. Above, we adopt SCE's proposals for increased inspections, and find it reasonable to infer that these inspections are likely to increase the number of unauthorized attachments identified. In order to reflect this likely increase in penalties and encourage SCE to ensure it is not under-collecting maintenance and inspection credits, we adopt a modest increase to SCE's total joint pole credit forecast to $4 million.

TURN also proposes that we initiate a review of the rates for pole credits. TURN expresses concern that SCE ratepayers may bear more than their share of the cost and risk of pole maintenance and activities.[251] SCE replies that TURN is conflating renters and joint owners, and notes that rental rates under mandatory access are set by statute. SCE recommends R.14-05-001 as a more appropriate venue for this subject.[252] From the record before us in this proceeding, it is impossible to reach detailed conclusions about this issue here. Therefore, we agree with TURN that a review is worthwhile. SCE shall undertake such a review and present information in its next GRC on its efforts to ensure that SCE ratepayers are not unduly subsidizing other companies' use of jointly owned poles. In this review, SCE should include descriptive information on the number of joint owned and rented poles and cost sharing in each case. SCE should coordinate this review with its review of capital costs discussed in Section 7.7.3.1.3 below.

[251] TURN OB at 96-98.
[252] SCE RB at 57-58.

7.6.3.2. FERC Accounts 593.120 & 594.120

SCE's total forecast for Account 593.120 is $139 million, up from $124 million recorded in 2012; for 594.120 SCE forecasts $27 million, which is the same as 2012 recorded.[253] Most elements of these accounts are uncontested, and we find SCE's forecast reasonable. ORA contests the new overhead conductor program based on a perceived lack of evidence.

SCE claims that the overhead conductor program will evaluate the entire overhead distribution system in seven years (beginning late 2013) to mitigate conductor failure risk and improve public safety. SCE's forecast of $4.360 million (86% labor) is based on inspecting conductors associated with 206,000 poles per year and its assumptions about the number of remediation activities to splices and connectors. SCE contends it is advisable to perform analysis of this type and plan for mitigation as opposed to simply beginning to reconductor all lines.[254]

ORA forecasts $1.453 based on its "normalized" version of SCE's forecast. ORA considers SCE's support for the program lacking, and cites the lack of historical data.[255]

ORA does not appear to dispute the specific assumptions underlying SCE's cost forecast or SCE's rationale for the overhead conductor program. We find SCE's rationale for the program and its cost forecast reasonable. No other elements of these two FERC accounts are disputed, and we approve SCE's forecasts for Accounts 593.120 and 594.120.

SCE proposes to transition its Bark Beetle-related vegetation management expenses from the Catastrophic Event Memorandum Account (CEMA) to base

[253] SCE-3V6P1 at 55-56.
[254] SCE-3V6P1 at 35-36; SCE-15 at 20.
[255] ORA-9 at 21-24.

rates and close the Bark Beetle CEMA because these costs have stabilized. No party opposes the change, and we approve this request.

7.6.4. Poles – Capital Expenditures

In this section, we address various pole-related capital expenditure issues. Some of these subjects are inter-related with the Pole Loading Program (PLP) that is discussed in detail in section 7.7 below.

7.6.4.1. Pole Replacement Unit Cost

SCE uses 2012 recorded data as the basis of its unit costs for all pole replacements (deteriorated pole, aged pole, and PLP). In constant 2012$, SCE forecasts $12,130 for each distribution pole and $19,800 for each transmission pole.[256] ORA supports these forecasts.[257] A different ORA witness appears to have made a three-year average calculation of unit costs, but does not provide details.[258] SCE alleges that the second witness's calculation is not correct because it relies on nominal dollars.[259] TURN contests SCE's unit costs, noting that some cost components increased much faster than inflation between 2009 and 2012. TURN notes that the largest increase is contractor costs ($1,820 from 2011 to 2012 for transmission), which is only partly offset by a decline in labor costs. TURN submits that SCE must "do better containing these costs" and should consider using more employee labor and less contractor labor given the 12-year PLP. TURN recommends using four-year averages: $11,288 for distribution (11% real increase relative to 2009), and $18,272 for transmission (16%) (2012$). Relative to SCE's proposal, TURN's forecast is a 7% reduction for distribution and 6% for transmission.[260] In rebuttal, SCE maintains that 2012 recorded costs "reflect the

[256] SCE-3V6P2 at 26-27, SCE-3V6P1 at 46-47.
[257] ORA-11 at 80.
[258] ORA-12 at 11.
[259] SCE-19V6P1 at 39.
[260] TURN-20 at 7-8.

most recent mix of tasks required for pole replacements" and are therefore the best forecast of future costs.[261] SCE's rebuttal does not address TURN's fundamental point that SCE has not adequately justified the rate of cost increases or shown that it is taking appropriate steps to control costs. Nevertheless, SCE's proposal is consistent with our guidance to use LRY when there is a clear trend in historical data. In order to give SCE an incentive to contain the unit costs, we adopt a 3% reduction to SCE's unit costs for both transmission and distribution pole replacements. This forecast is summarized below (2012$).

	2012 Recorded	SCE forecast	TURN forecast	Adopted
Distribution	12,123	12,130	11,288	11,766
Transmission	19,436	19,800	18,272	19,206

Converted to nominal dollars, the adopted forecast of pole replacement unit costs is:

	2014	2015
Distribution	12,322	12,583
Transmission	19,956	20,486

Separately, TURN contends that SCE miscounts the cost of removal of jointly owned poles.[262] SCE shows that its forecast is based on the recorded, average costs actually incurred by SCE, net of joint pole credits.[263] Thus, SCE's forecast does not double count in this way, and we make no change on this basis.

7.6.4.2. Deteriorated Pole Replacements

The Deteriorated Pole Replacements are based on inspection programs described above in Section 7.6.3. We approved SCE's forecasts for both ODI and intrusive inspections.

[261] SCE-19V6P1 at 44.
[262] TURN-20 at 16-18.
[263] SCE-19V6P1 at 40-42.

SCE describes the following priority ratings based on the inspections, the number of poles to be replaced each year is determined by the "due date" for replacements from poles failing inspection.

1. Priority 1 if the pole needs to be replaced within 72 hours of inspection
2. Priority 2A, if the pole needs to be replaced within one year of inspection
3. Priority 2B, if it needs to be replaced within two years of inspection
4. Priority 2C, if it needs to be replaced within three years of inspection

SCE's unit forecast is summarized below.[264]

(# of poles)	2014	2015
Distribution	6,100	6,602
Transmission	1,500	1,500

ORA recommends 8,670 distribution pole replacements per year, based on the 2010-2012 average and 667 transmission poles per year based on a 2009-2011 average. ORA notes that the SCE's proposed rate of distribution pole replacements is lower than the historical average that ORA recommends.[265]

TURN recommends a 3% reduction in the number of poles replaced, due to its calculation of the likely overlap between PLP and deteriorated pole replacements.[266]

SCE suggests that TURN is double-counting the overlap because deteriorated pole replacement estimates were included in the forecast of other

[264] SCE-3V6P1 at 40-43.
[265] ORA-12 at 11 and 16.
[266] TURN-20 at 32-34.

programs and comments that forecasting these overlaps is complex. SCE recommends balancing account treatment for this reason.[267]

Further, SCE argues that its forecast of transmission pole replacements is reasonable, and that 3,285 of 4,500 poles to be replaced have already been identified through inspections. SCE argues that its predictions for additional poles failing inspections are based on historical failure rates.[268]

We find SCE's forecast of deteriorated pole replacements, based on inspection failures, reasonable. Applying our adopted unit costs to SCE's forecasted number of poles, we calculate a capital expenditure forecast as summarized below.

			2014	2015
Distribution	Poles		6,100	6,602
	Nominal$, millions	Adopted	71.773	83.072
		Requested	77.486	85.644
Transmission	Poles		1,500	1,500
	Nominal$, millions	Adopted	28.809	30.730
		Requested	30.859	31.680

7.6.4.3. Aged Pole Replacements

SCE claims it must transition from replacing less than 10,000 poles per year under the deteriorated pole program, to greater than 35,000 in combination of deteriorated pole and PLP (discussed in Section 7.7. below). To smooth the transition, SCE created the aged pole program to replace poles 70 years old and older. According to SCE's analysis, 70-year old poles have an 88% chance of failing an inspection or failing in service by age 80. SCE has over 46,000 poles age 70 or more, or about three percent of its pole population. SCE forecasts the number of aged (70+ year old) poles to be replaced each year by subtracting PLP

[267] SCE-19V6P1 at 43.
[268] SCE-19V6P1 at 45.

and deteriorated pole replacements from its target number of total pole replacements. SCE forecasts 14,500 aged pole replacements in 2014 and 1,898 in 2015.[269]

ORA opposes the aged pole program, noting that it has not previously been authorized by the Commission. ORA claims that the poles studied by SCE to analyze aged poles were installed between 1951 and 1960, and thus will not begin turning 70 until 2021. ORA claims that SCE's GO 165 reports do not support SCE's calculated 88% failure rate. ORA concludes that this program is not supported by engineering data and should be denied.[270]

TURN "strongly opposes this expenditure as unnecessary and imprudent, shortening the life of poles that are otherwise meeting inspections and functioning adequately." TURN notes that 2013 aged pole replacements were lower than forecast because SCE prioritized other pole replacements. TURN claims the PLP pilot study shows "roughly the same" failure rates for poles under and over age 70. TURN submits that poles that have passed their last inspection should not be "presumed" to need replacement. TURN observes that newer poles appear to have shorter mean time to failure than older poles, and hypothesizes that mean time to failure in SCE's data is driven by pole inspections, and that many poles "failed" after the inception of GO 165 and the resulting inspection program in 1997. TURN generally questions the data and conclusions of SCE's analysis. TURN comments that if we find a need to ramp up pole replacements, we should address high priority work, namely deteriorated poles or overloaded poles.[271]

[269] SCE-3V6P1 at 43-47.
[270] ORA-12 at 11-16.
[271] TURN-20 at 40-44.

CUE contends that SCE's proposal is too slow and too short in duration because it would leave aged poles on the system. Consequently, CUE proposes that SCE continue the aged pole replacement program through 2017 at a slower rate than SCE proposes for 2013-2014.[272]

In rebuttal, SCE argues that statistical analysis supports the Aged Pole replacements and analogizes this program to the infrastructure replacement programs discussed in Section 7.4 above. SCE claims that ORA mischaracterizes statistical data. SCE states that the average inspection failure rate for aged poles is over 25% for twelve years, and that its statistical models (only including vintages in the data set) show annual failure rate of 3.8% per year for poles age 60 and over. Further, SCE argues that this same data[273] shows that aged poles are approximately twice as likely to fail inspections as younger poles, on average. SCE rejects TURN's argument about the relation between inspection counts and failed inspections, noting that an inspection not completed cannot result in a failure. SCE replaced 5,330 poles in 2013 and states that, at the time of rebuttal testimony, it was on schedule to meet its forecast of 14,500 aged pole replacements in 2014. SCE concludes that TURN and ORA recommendations to disallow aged pole expenditures are confiscatory because the new poles are used and useful.[274]

The fact that the new poles provide service to ratepayers and are used and useful is insufficient to prove that the expenditures to purchase and install the poles should be recovered from rates. That question turns on the prudency of the investment decision.

[272] CUE-1 at 7-13.
[273] See: SCE-19V6P2 at A-32.
[274] SCE-19V6P2 at 50-56.

SCE apparently misunderstands TURN's argument that the new (in 1997) GO 165 inspection program led to a temporary increase in inspection failures. The point is not that failure *counts* were higher in years with high inspection counts; the point is that failure *rates* are much lower beginning in 2009, after poles were being inspected for the second time under the new program. SCE's data clearly shows lower failure rates for all poles (both aged and non-aged) that are much lower in 2009 and beyond than in 2008 and earlier.

Another key argument SCE makes in support of the aged program is that it is necessary to "ramp-up" replacement rates to minimize execution risk of the considerably higher volumes of pole replacements it forecasts for the PLP. As discussed in Section 7.7.3.1.3 below, we partly approve SCE's PLP forecast and make a significant reduction to the number of pole replacements in PLP. This reduction in turn reduces the need for aged pole replacements as a "ramp-up" program.

We support SCE's goal of reducing the risk of an in-service pole failure. However, SCE has not demonstrated that the aged pole replacements are prudent, at the level requested. For instance, SCE has not presented any cost-benefit analysis relative to alternative approaches to aged poles, such as higher frequency of inspections for aged poles or pole reinforcements. As discussed in Section 7.4 above, infrastructure replacement may be appropriate in circumstances of limited effective testing options; SCE has not demonstrated this circumstance in the case of the aged pole replacements.

In order to balance these varying factors, we approve 9,000 aged pole replacements in 2014 and zero in 2015. This level provides a reasonable ramp up in 2014 toward the approved level of pole replacements for PLP in 2015, making 2014 approximately a mid-point between 2013 and 2015 levels. Moreover, this

aged pole funding level recognizes that a portion of the aged poles actually replaced by SCE in 2014 are in fact providing value to ratepayers because some of the replaced poles may have otherwise failed in service. However, we also recognize that another portion of these new poles replaced existing poles that could have continued to serve ratepayers for years to come.

For context of the ramp-up effect, our approved pole replacements are shown below.

	2008	2009	2010	2011	2012	2013	2014	2015
Deteriorated	9,354	8,291	7,194	8,399	8,794	7,500	7,600	8,102
Aged						5,330	9,000	-
PLP							3,000	18,213
Total	9,354	8,291	7,194	8,399	8,794	12,830	19,600	26,315

The approved forecast is summarized below:

Aged Pole Replacements		2014	2015
Poles Replaced	Adopted	9,000	0
	Requested	14,500	1,898
Nominal$, millions	Adopted	114.32	0
	Requested	184.189	24.622

7.6.4.4. Joint Pole Replacement Capital Credits and Wood Pole Disposal

SCE forecasts $844 in capital credits per pole replacement, regardless of which program replaces the pole. SCE's total capital credit forecast for 2015 for Deteriorated Poles, Aged Poles, and other programs (excluding Pole Loading Program) is $16.244 million (nominal $) in 2015. For wood pole disposal, SCE

forecasts $100 (2012$) per pole based on a five-year recorded average.[275] SCE's pole disposal unit cost forecast is uncontested and is adopted. We address the subject of capital credits per pole in Section 7.7.3.1.1 below and adopt SCE's forecast.

	2012$	Nominal$	
		2014	2015
Disposal	$100.00	$104.72	$ 106.95
Credit	$844.00	$883.85	$ 902.62

Applying the adopted credit and disposal amounts to our forecast of pole replacements yields the following capital forecast.

Joint Pole Replacement Capital Credits and Wood Pole Disposal (Nominal$, millions)	SCE		Adopted	
	2014	2015	2014	2015
Aged Poles- Disposal	$1.518	$0.203	$0.942	$-
Aged Poles-Joint Pole Credit	$(12.816)	$(1.713)	$(7.955)	$-
Deteriorated Distribution Poles-Disposal	$0.639	$0.639	$0.706	$0.706
Deteriorated Distribution Poles-Credits	$(5.391)	$(5.391)	$(5.959)	$(5.959)
Deteriorated Transmission Poles-Disposal	$0.157	$0.160	$0.157	$0.160
Deteriorated Transmission Poles-Credits	$(1.326)	$(1.354)	$(1.326)	$(1.354)
Total	$(17.219)	$(7.456)	$(13.434)	$(6.447)

7.6.5. Other Capital

SCE's capital expenditure forecasts that are not specifically addressed are uncontested and are adopted. Some expenditures (e.g., removal of idle facilities) were initially contested, but the parties reached agreement through stipulation.[276]

[275] SCE-3V6P1 and SCE-3V6P1A at 50-53.
[276] ORA-57R.

7.7. T&D – Pole Loading

"Pole loading" refers to the calculation of whether a pole meets certain design criteria called "safety factors" based on wind in that location and facilities attached to the pole. GO 95 establishes pole loading safety factors for California utilities. Pole loading calculations consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys. Some of the information related to third party attachments may not be known to SCE, such as unauthorized attachments.

SCE is required to allow certain other utilities to attach to poles and approximately 70% of poles are shared. Joint owners are responsible for pole loading calculations when attaching to a pole; renters are responsible for providing the necessary input to SCE, who will then perform the calculation.

SCE notes that safety factors have increased over time, and some older poles may not meet current standards. Further, the technology and approach for performing pole loading calculations has changed considerably over time, as have the number and type of attachments placed on poles. Also, poles that do comply with safety factors may still fail.

Pole loading is a significant safety issue; overloaded poles may have contributed to the 2007 Malibu Canyon Fire. This event has increased the scrutiny of pole loading issues. In addition to indirect damage from fires, poles or the equipment they support can directly injure people or damage property in the event of a pole failure. Finally, a pole failure can lead to an outage. SCE states that overloaded poles are more likely to fail, especially during wind storms or other unusual conditions.

In D.12-11-051,[277] we ordered SCE to undertake a study of pole loading. SCE claims that preliminary results of this study inform its forecasts for pole loading. Additionally, SCE has hired a meteorological firm to help update its designated high wind areas.

SCE proposes a comprehensive PLP to address pole loading issues. The program is designed to assess non-engineered poles and structures for compliance with GO 95 and SCE's internal standards. SCE proposes a seven-year (2014-2020) assessment program, which will evaluate the highest priority poles in the first three years. SCE's planners will review the assessments and design remediation approaches including repair (e.g., adding guys) or replacement of poles. The planners will attempt to efficiently coordinate the remediations with other work in the region (e.g., undergrounding, infrastructure replacement). SCE intends to complete the remediations by 2025. Further, SCE intends to improve the joint pole process to reduce pole loading problems through better information sharing. To this end, SCE is participating in several Commission proceedings and working with the SCJPC.

SCE forecasts 2015 O&M of $38.424 million (2012$) and capital expenditures of $40.672 million in 2014 and $341.295 million in 2015 (nominal$). SCE forecasts slightly increasing capital expenditures in each of 2016 and 2017 for a total capital forecast of $1.089 billion (nominal$) for 2013-2017. SCE shareholders have pledged to contribute $17 million toward pole loading in the Malibu area as a result of a settlement. SCE's forecast is net of this amount, which is mostly applied to reducing the capital expenditures during 2015-2017.

The PLP began after the 2012 GRC and the activities are incremental to the DIMP and other pole activities discussed in this decision. Therefore, with limited

[277] At 181-182.

exceptions, SCE did not have recorded costs or past authorizations to present along with its forecasts.[278]

One key contested issue is the number of poles to be replaced during this GRC period and the corresponding capital expenditures. ORA and TURN propose significantly lower numbers than SCE, while CUE proposes higher numbers. TURN notes that:

- capital expenditures in the PLP could exceed $3 billion over the 12-year replacement cycle,
- SCE forecasts capital related revenue requirement increases of $35 million for 2016 and $60 million for 2017 due to prior PLP capital expenditures,
- The capital revenue requirement for PLP could exceed $500 million per year by 2026.

While TURN acknowledges uncertainty in the magnitude, TURN concludes that PLP will lead to "hugely increasing revenue requirements."[279]

7.7.1. SCE's Pole Loading Study

As discussed above, SCE performed a pole loading study after the 2012 GRC, served on July 31, 2013. SCE's sample of poles studied is summarized below:

[278] SCE-3V6P2, SCE-19V6P2, and SCE-15.
[279] TURN-20 at 6-7.

Stratum	High Fire	Wind Loading (psf)	Population of utility poles (N_i)	Population weight ($W_i=N_i/\Sigma N_i$)	Sample size (n_i)	Sample weight ($w_{i=}\ n_i/\Sigma n_i$)	Sample proportion (n_i/N_i)
1	No	6	17,562	1.23%	150	3.00%	0.85%
2	No	8	572,365	40.22%	1,790	35.76%	0.31%
3	No	12	309,062	21.72%	849	16.96%	0.27%
4	No	18	43,487	3.06%	132	2.64%	0.30%
5	Yes	6	103,119	7.25%	751	15.00%	0.73%
6	Yes	8	172,662	12.13%	759	15.16%	0.44%
7	Yes	12	180,831	12.71%	464	9.27%	0.26%
8	Yes	18	24,013	1.69%	111	2.22%	0.46%
Total			**1,423,101**	**100.00%**	**5,006**	**100.00%**	**0.35%**

SCE defines high wind areas as "regions in which, based on SCE's judgement and the analyses of subject matter experts, the appropriate wind load used for pole design exceeds the GO 95 minimum of eight pounds per square foot (psf)." Thus, strata 3, 4, 7, and 8 are high wind regions. SCE uses boundaries defined by the California Department of Forestry and Fire Protection to define the high fire areas (HFA), including strata 5-8.

SCE also provides a later (May 2014) table summarizing the number of poles in the different wind and fire areas. SCE notes that the number of poles is slightly larger. Using this table, SCE calculates that 59% of poles are in a high wind area (>8 psf), HFA, or both.[280]

Wind Rating (psf)	no HFA	HFA	Total
6	60,134	148,055	208,189
8	520,511	45,197	565,708
12	407,995	95,801	503,796
18	104,310	39,645	143,955
24	4,180	1,077	5,257
Total	1,097,130	329,775	1,426,905

[280] SCE-76.

We note that, in addition to the slight increase in total pole count, there are some other important differences between this table and the preceding table. First, the 24 psf category was not originally included. Second, large decreases in the number of poles in strata 2, 6, and 7 are offset by increases in the other categories (including the 24 psf poles in the 18 psf strata for comparison purposes). More total poles are shown in the high wind areas (12 to 24 psf) and non-HFA regions. These shifts are summarized below.

	Shift from low to high wind		Shift from HFA to non-HFA	
Wind (psf)	6, 8	12, 18 (including 24)	Any	Any
Strata	1, 2, 5, and 6	3, 4, 7, and 8	1 to 4	5 to 8
Change	-91,811	95,615	154,654	-150,850

7.7.2. O&M

PLP O&M includes several activities and FERC accounts. Our total adopted forecast is summarized below (millions of 2012$).

Account	Activity	Labor	Non-Labor	Total
593.125	Related Expense	$0.520	$1.480	$2.000
	Repair	$5.132	$3.202	$8.334
	Malibu Adjustment	$0	$(0.537)	$(0.537)
	Total	$5.652	$4.145	$9.797
571.125	Related Expense	$0.064	$0.292	$0.356
	Repair	$0.634	$0.396	$1.030
	Total	$0.698	$0.688	$1.386
583.125	Joint Pole Organization	$1.123	$0.125	$1.247
	Distribution Assessments	$13.034	$7.989	$21.023
	Total	$14.157	$8.114	$22.270
566.125	Transmission Assessments	$1.611	$0.988	$2.599
Total		$22.118	$13.394	$36.052

7.7.2.1. Assessments and Planning (Accounts 583.125 – Distribution and 566.125 – Transmission)

Assessments will be performed by contractors and recorded as non-labor expenses; planning activities are recorded as labor expenses. Additionally, $0.844 million in the 2013 forecast is for the pole loading study ordered by D.12-11-051. Beginning in 2015, SCE forecasts performing 205,754 poles per year at $111 per pole ($22.839 million 2012$) and dedicating 14 planners to the PLP ($1.812 million) for transmission and distribution, combined. $21.939 million of this total is for distribution, $2.712 million is for transmission. SCE plans to complete the assessments in seven years.[281]

ORA forecasts $14.663 million for distribution and $1.812 million for transmission assessments. ORA notes that spending and assessments completed

[281] SCE-3V6P2 at 19-21.

during the first five months of 2014 represent only 7% of the forecast total for the year. In ORA's view, 2014 results suggest that SCE cannot actually complete the assessments at the rate assumed in SCE's forecast. ORA argues that SCE does not have adequate experience or historical data to forecast the PLP assessments. To calculate its forecast, ORA assumes a ten-year assessment schedule, or 144,028 assessments per year. Further, ORA applies a unit cost of $106 per pole, based on SCE's 2014 recorded costs as of May.[282]

SCE contends that its proposed seven-year time frame is an appropriate balance between safety and execution risk. Early months of a large program, SCE argues, should not be used to discount SCE's ability to execute during the test year. Further, SCE contends that the balancing account proposed for the PLP (see Section 7.7.3.1.3 below) shields customers from the cost risk of SCE being unable to execute as many assessments as authorized. Nevertheless, SCE offers that it can maintain its proposed prioritization of PLP on high risk regions in a ten-year assessment program, if requested to do so. Separately, SCE contests ORA's proposed lower unit cost, claiming that preliminary 2014 results are an insufficient basis for this reduction.[283]

TURN recommends that the assessments include data relevant to alternatives to pole replacement or for cost sharing, such as which companies have attachments on the pole and the load of each attachment.[284] SCE does not directly respond to this point. We agree with TURN that this data should be recorded in the assessment process.

We adopt ORA's proposed unit cost of $106 per pole. While we agree with SCE that preliminary recorded data should not always be used for forecasting, in

[282] ORA-8 at 25-32.
[283] SCE-19V6P2 at 4-5.
[284] TURN-20 at 29.

this instance SCE has not advanced any other persuasive rationale for its own forecast. Further, SCE itself expects the pace of assessments to increase in the future, which may decrease unit costs due to economy of scale.

We accept SCE's proposed assessment schedule. We find that the public interest in quickly developing a more comprehensive understanding of the extent of overloaded poles outweighs the potential cost deferral advantage of slowing the pace of assessments. Further, we adopt SCE's uncontested forecast of planning and analysis costs. Our adopted forecast is below.

Assessments per year	205,754
Unit Cost (2012$)	$ 106
Subtotal (millions of 2012$)	$ 21.810
Planning & Analysis Cost (millions of 2012$)	$ 1.812
Total Assessment Cost (millions of 2012$)	$ 23.622
89% to 583.125 – Distribution[285]	$ 21.023
11% to 566.125 - Transmission	$ 2.599

7.7.2.2. Repair (Accounts 571.125 – Transmission and 593.125 – Distribution)

SCE intends to repair poles, specifically, guy wires at electrical levels within two years of an inspection that identifies needed repairs. Repairs (as opposed to replacements) are relevant to all poles with deficient guy wire safety factors and 40% of poles with vertical or buckling safety factor failures. SCE estimates that 3% of poles will need repairs, and forecasts 2,100 repairs in 2014 and 5,700 per year beginning in 2015. SCE estimates unit planning costs of $89 per pole based on contractor rates and $1,554 (2012$) based on 2012 recorded values. SCE's total O&M forecast is $9.364 in 2015 (millions of 2012$).[286]

[285] Allocated to the Distribution vs Transmission accounts using the same ratio as SCE-3V6P2.
[286] SCE-3V6P2 at 21-22.

ORA accepts SCE's unit costs, but projects a lower rate of repairs based on a ten-year assessment schedule as discussed above. Additionally, ORA contends that SCE overestimated its ability to ramp up repair rates during 2014.[287]

As discussed above, we find SCE's proposed pace of assessments reasonable. SCE's unit costs are uncontested and are reasonable. Therefore, we accept SCE's forecast of repair costs, as shown below.

Account	Approved (millions of 2012$)
593.125	8.334
571.125	1.030

7.7.2.3. Related Expense (Accounts 571.125 – Transmission and 593.125 – Distribution)

This category records costs related to capital expenditures (pole replacements) that do not qualify for capitalization. SCE's forecast is summarized below.[288]

Account	Requested (millions of 2012$)	Labor
593.125	2.745	26%
571.125	0.489	18%

ORA proposes reducing SCE's forecast by 19.68% to match ORA's proposed reductions to SCE's replacement forecast (discussed in Section 7.7.3.1 below).[289] SCE acknowledges that this forecast should be adjusted dependent on the approved replacement forecast.[290] The relation between the replacement forecast and related expense is uncontested and is reasonable. We apply the ratio

[287] ORA-8 at 32-34.
[288] SCE-3V6P2 and SCE-3V6P2A at 23-24.
[289] ORA-8 at 35.
[290] SCE-19V6P2 at 7.

of approved to requested pole replacements in 2015 (72.9%) to calculate this forecast (millions of nominal$).

Account	593.125	571.125
Labor	0.520	0.064
Non-Labor	1.480	0.292
Total	2.000	0.356

7.7.2.4. Joint Pole Organization (JPO) (Account 583.125)

As discussed in Section 7.6.3.1.3 above, JPO manages poles that SCE owns jointly. SCE forecasts 24 additional JPO employees to handle its proposed 25,000 annual pole replacements, beginning in 2015. SCE's total forecast is $1.712 million, of which 90% is allocated to labor.[291]

ORA proposes reducing SCE's forecast by 19.68% to match ORA's proposed reductions to SCE's replacement forecast (discussed in Section 7.7.3 below).[292] SCE acknowledges that this forecast should be adjusted dependent on the approved replacement forecast.[293] The relation between the replacement forecast and JPO expense is uncontested and is reasonable. We apply the ratio of approved to requested pole replacements in 2015 (72.9%) to calculate this forecast (millions of nominal$).

Account	583.125
Labor	1.123
Non-Labor	0.125
Total	1.247

[291] SCE-3V6P2 at 25-26.
[292] ORA-8 at 36.
[293] SCE-19V6P2 at 9.

7.7.3. Capital

The primary capital item is the replacement of poles failing pole loading assessments. In addition to the number and timing of pole replacements, cost recovery for joint poles is a disputed issue. Our adopted capital forecast is summarized below (millions of nominal$).

	SCE		Adopted	
	2014	2015	2014	2015
Pole Replacements - Distribution	$33.916	$288.636	$32.899	$203.963
Pole Replacements - Transmission	$6.789	$58.080	$6.585	$41.043
Malibu Adjustment		$(5.130)	$-	$(5.130)
Distribution Transformers	$1.371	$11.668	$1.371	$ 8.500
Prefabrication	$0.931	$7.926	$0.931	$5.774
Joint Pole - Distribution	$(2.360)	$(20.083)	$(2.360)	$(14.631)
Joint Pole - Transmission	$(0.289)	$(2.476)	$(0.289)	$(1.804)
Wood Pole Disposal	$0.314	$2.674	$0.314	$1.948
Total	$40.672	$341.295	$39.452	$239.664

7.7.3.1. Pole Replacements

7.7.3.1.1. Joint Poles, Attachments, and Cost Recovery

As noted above, SCE forecasts $844 in credits from joint owners per pole replaced (2012$); these credits offset a portion of the costs to ratepayers. This figure is based on a five-year recorded average.[294] ORA does not contest the unit credit amount.

TURN makes several proposals related to non-SCE equipment on poles found to be overloaded by SCE's PLP assessments. Generally, in TURN's view, SCE's proposal places too much of the burden of PLP replacements on SCE ratepayers and too little on joint owners and/or renters. TURN challenges two

[294] SCE-3V6P2A at 31.

assumptions of SCE's proposal: 1) removing attachments is not an option to remediate an overloaded pole; and 2) pre-existing cost allocation practices (between SCE and attachers) must be used for PLP replacements. TURN makes numerous arguments and assertions on this subject. We do not attempt to repeat TURN's showing here, but only to summarize key themes.

In support of its view, TURN notes that our decision instituting mandatory access also concluded that electric utilities should be allowed to place restrictions on attachments in order to protect safety and reliability.[295] TURN further suggests that we have expressed interest in cost-sharing arrangements related to upgrades of joint poles.[296]

PLP replacements should not necessarily be treated as "mutual benefit" remediation, TURN contends, because SCE has not analyzed whether any replacements should be considered "rearrangements" for which all costs would be borne by an attacher. This would be appropriate if there is an unauthorized attachment or if the last attacher is the cause of the overload.

TURN acknowledges the role of the Southern California Joint Pole Committee (SCJPC), of which SCE is one of 33 members, in setting the rates for pole replacement and other costs. TURN provides a hypothetical example of SCE ratepayers paying 64% of the SCJPC authorized new pole cost with the remainder paid by the joint owner. SCE ratepayers also pay 100% of the substantial difference between SCE's total cost and the SCJPC authorized amount. Renters typically do not pay for pole replacements. However, TURN enumerates paragraphs of the SCE attachment contracts (negotiated with California Cable and Telecommunications Association, representing renters) that TURN believes may allow SCE to charge renters for replacements or remove

[295] See: D.98-10-058 at 72.
[296] See: D.14-02-015 at 33.

attachments in pole overloading circumstances. TURN criticizes SCE for not presenting analysis on the impact of removing attachments.

TURN considers the SCJPC approach inappropriate for PLP, due to the scale of the program and nature of the pole loading problem. TURN further emphasizes that our mandatory access decision was premised on the idea of "surplus space, or use of excess capacity"[297] and suggests that attachments may not be on excess capacity to the extent that they contribute to pole overloading.

Further, TURN shows that poles with non-SCE attachments are significantly more likely to fail the bending analysis in the Pole Loading Study. Similarly, in a 2012 study, poles with attachments were found to be 64% more likely to not meet GO 95 safety factors. TURN concludes that, absent attachments, the percentage of poles failing the bending analysis (and thus needing replacement) would be considerably lower than the 19% proposed by SCE.

TURN notes that the $844 per pole credit corresponds to 7% of SCE's proposed $12,130 unit cost.

TURN contends that SCE's attachment fees may be below SCE's cost-of-service, and recommends that we order SCE to conduct a study on this issue. The study should include direct, administrative, information technology, and other costs that are reasonably allocated to attachments.

TURN contends that SCE's forecast double counts removal and disposal costs in its net credit calculations. TURN notes that the last owner to remove equipment from a pole is responsible for removal and disposal of joint poles, and that SCE is not usually responsible for this work. As a result, TURN proposes

[297] D.98-10-058, Appendix A at 3.

reducing removal and disposal costs by 56%, corresponding to the fraction of poles that other owners remove.

TURN notes that SCE proposes wind standards greater than 8 pounds on 46% of poles, consistent with Rule 31.1 of GO 95.

TURN specific proposals:

- Catch-up fee: TURN proposes that we authorize SCE to charge a PLP specific catch up fee for each pole found to need replacement that supports an attachment. TURN views PLP as a catch-up program for which responsibility is shared, benefits are shared and costs should also be shared. TURN suggests that this fee would also send an appropriate price signal to attachers. Such fees should be considered as Contributions in Aid of Construction (CIAC) to offset capital costs. TURN does not recommend a specific fee amount or structure.
- Electric-service first: TURN proposes that if an existing pole could safely support SCE equipment, without attachments, SCE should pursue an outcome consistent with such an option. The attacher would be notified that space is no longer available and given the choice to either relocate or pay a larger share of the replacement costs. TURN considers the portion currently paid by joint owners to be too low and claims that renters pay less than $20 per year, 70% of which is captured by shareholders. TURN describes options for attachers to relocate, and argues such options should be explored.[298]

SCE generally rejects TURN's arguments on procedural grounds but expresses interest in coordinating with TURN on proposals related to cost recovery. Specifically, SCE notes that attachers (whether renters or owners) are not parties to this proceeding and suggests that R.14-05-001 is a more appropriate forum. SCE also notes that there are significant policy questions (e.g., impacts on communications infrastructure including 911 service) that may arise from removing attachments.

[298] TURN-20.

SCE also discounts TURN's assertion that rental fees are recorded to Non-Tariffed Products and Services (NTP&S), and clarifies that only a small portion (i.e., rents from entities not entitled to mandatory access) goes to NTP&S.[299]

CUE comments that TURN's suggestions are fine, but are not guaranteed to work. Accordingly, CUE recommends that we authorize PLP replacements without making any assumptions about alternative solutions. Further, CUE suggests that we provide SCE an incentive, in the form of shareholders keeping a portion of savings, to successfully realize TURN's proposals.[300]

7.7.3.1.2. Number of Pole Replacements

Based on preliminary results of the Pole Loading Study, SCE anticipates 19% of poles will require replacement. Parties' forecast pole replacement rates (poles/year) are summarized below, with the 2015 rate forecast to continue through 2025.

Party		2014	2015
SCE	Distribution	2,670	22,250
SCE	Transmission	330	2,750
SCE	Total	3,000	25,000
ORA	Distribution	0	17,871
ORA	Transmission	0	2,209
ORA	Total	0	20,080
TURN	Distribution	n/a	18,854
TURN	Transmission	n/a	2,330
TURN	Total	n/a	21,184
CUE	Distribution	2,670	29,370
CUE	Transmission	330	3,630
CUE	Total	3,000	33,000

[299] SCE-19V6P2 at 15-16.
[300] CUE-2 at 27-28.

At SCE's proposed unit costs, SCE's total forecast is $347 million (nominal$) in 2015;[301] however, applying the unit costs adopted in Section 7.6.4.1 above to SCE's proposed number of pole replacements, the forecast would be reduced to $336 million. For purposes of simplifying discussion in this section, we will only address forecast pole replacements, and apply the adopted unit cost to our adopted unit count in the conclusion.

ORA proposes two separate reductions to SCE's proposed replacement rates. First, ORA calculates that in order to replace the 268,688 poles that SCE claims need to be replaced by 2025 only requires replacing 24,153 poles per year from 2015 on. Second, ORA calculates an 11-year recorded average of 21,443 poles replaced per year under other programs (not including Aged Pole Replacements), and assumes that 19% of these would have been replaced under PLP. Therefore, to avoid this overlap in pole replacement programs, ORA proposes an additional reduction of 4,074 poles per year (0.19 * 21,443 = 4,074). ORA proposes no pole replacements in 2014 and 20,079 poles per year beginning in 2015.[302]

TURN supports ORA's proposed reduction of 847 poles per year based on SCE's "over forecast." Further, TURN estimates an additional reduction of 2,969 poles per year based on its estimate of overlap with other programs for a total forecast of 21,184 poles per year beginning in 2015. TURN does not explicitly address 2014. TURN recommends that the PLP initially focus on high hazard areas, but does not propose any specific reduction on that basis.[303]

CUE recommends a higher replacement rate of 33,000 poles per year in 2015 and beyond. CUE contends that this will reduce the delay in remediating

[301] SCE-3V6P2 at 26-28.
[302] ORA-11 at 76-81.
[303] TURN-20 at 33.

poles that have failed the PLP inspections, will not overextend SCE's capabilities, and will still be repairing fewer poles than are identified for replacement during this GRC period.[304]

In rebuttal, SCE contends that ORA and TURN overestimate overlap of PLP with other programs. SCE particularly rejects ORA's estimate of zero poles for 2014, claiming that 1.5% of SCE's proposed 3,000 is more realistic. SCE also argues that its assessments will identify more pole replacements than it will actually accomplish during this GRC period. Therefore, the impact of overlap will materialize later in the PLP program.

Separately, SCE explains that it structured the PLP replacements to end during the 12th year and that this explains the 847 poles per year reduction proposed by ORA. SCE recommends rejecting the reduction.[305]

7.7.3.1.3. Discussion

A few seminal facts are not disputed:

- A significant fraction, nearly 19%, of poles reviewed in SCE's PLP study are overloaded, and specifically failed the bending analysis. The study suggests similar failure rates in SCE's total population of poles. SCE proposes to replace these poles.
- An additional 3% of poles in the study are overloaded and could be repaired through addition or repair of guy wires. Again, the study suggests a similar rate in the total pole population. SCE proposes to repair these poles.
- Overloaded poles present a significant safety hazard and reliability risk.
- Approximately 70% of poles are joint use, supporting attachments of either renters, joint owners, or both.

[304] CUE OB at 36-38.
[305] SCE-19V6P2 at 12-15.

- Attachments contribute to overloading,[306] but the extent of this contribution is not clearly quantified in the evidentiary record of this proceeding.[307]
- SCE's proposal does not consider removing attachments or distinguish between joint use and SCE-only poles for purposes of determining what remediation strategy to select. SCE's proposal relies on pre-existing cost sharing arrangements for joint use poles.
- SCE's 2015 capital forecast includes distribution pole replacements of $288.636 million, offset by $20.083 million in credits from joint users, and transmission pole replacements of $58.080 million, offset by $2.476 million in credits (nominal$).[308] These credits are less than 10% of the pole replacement forecast.
- Joint owners and renters are generally not parties to this proceeding and the costs and other implications of removing their attachments is not clearly detailed in the evidentiary record of this proceeding.

Based on these facts, we agree with the parties that some form of the PLP should be authorized. However, like TURN and ORA, we do not find that SCE has adequately justified its specific proposal.

First, we note that SCE has not clearly presented analysis of alternatives to pole replacement for poles failing the bending analysis. For example, SCE did not present a cost-benefit analysis of repairing, buttressing, or otherwise increasing the load carrying capacity of existing poles compared to replacing those poles.

Further, like TURN, we find that SCE has not explored all appropriate alternatives with respect to joint use poles in designing PLP. Unlike TURN, we decline to adopt any specific fee or surcharge because there is not an adequately

[306] See: RT 1427.
[307] See: RT 1496.
[308] SCE-19V6P2 at 10.

developed record on the subject.[309] TURN frames the issue from the perspective of SCE ratepayers with its electric service first principle, noting that from ratepayers' perspective it may be cost effective to pay penalties for terminating rental agreements rather than pay to replace poles. However, we also note that from the perspective of society more broadly, options besides replacing overloaded poles should be considered. If the cost to a joint owner (or to society, if there are externalities) is less to remove an attachment (ameliorating a hypothetical overload) than the total cost of replacing a pole (regardless of how that cost is allocated), the economically more efficient outcome is to remove the attachment. We agree with SCE that the implications of removing communications attachments may be significant. However, a statement of that possibility does not meet SCE's burden of proof that its implicit proposal not to fully explore this option is reasonable.

Before undertaking a program of this scale, SCE should have more fully explored additional options, including: renegotiating or terminating agreements or seeking higher replacement credits, either directly with joint owners and rentersor via SCJPC; evaluating the prevalence of unauthorized attachments; and, repairing, buttressing, or otherwise increasing the load carrying capacity of existing poles.

We agree with TURN that prior Decisions indicate that SCE can and should seek to negotiate with joint users to reach efficient sharing of joint poles and safely provide electric service. Specifically, in addition to the language cited by TURN, our decision on mandatory access states:

> We expect parties to resolve most issues relating to safety and reliability restrictions not explicitly covered in our rules through

[309] We agree with TURN that non-participation in a proceeding does not guarantee that a stakeholder's interests may not be impacted by the outcome of a proceeding. See TURN OB at 104.

> mutual negotiation among themselves. In the event that parties cannot resolve disputes among themselves over whether a particular restriction or denial of access is necessary in order to protect public safety or ensure the engineering reliability of the system, any party to the negotiation may request Commission intervention under the dispute resolution procedures we adopt below. In the event of such dispute, the burden of proof shall be on the incumbent utility to justify that its proposed restrictions or denials are necessary to address valid safety or reliability concerns and are not unduly discriminatory or anticompetitive.[310]

We note that the PLP assessments approved in Section 7.7.2.1 should provide exactly the factual information necessary to meet the burden of proof described in that decision, including the extent to which attachments contribute to any "valid safety or reliability concerns" and potentially non-compliance with GO 95 standards. Cost sharing in proportion to that contribution is not "unduly discriminatory or anticompetitive." Although we do not specifically require a stand-alone study of joint-pole issues, the PLP assessments should provide the raw data that would be the basis of such a study. SCE should use the assessment results to conduct any analysis it considers appropriate to support negotiations with joint owners and renters.

In Section 7.6.3.1.3 above, we express concerns about O&M credits of joint poles and direct SCE to present additional information on that subject in the next GRC. We follow the same path here. In the next GRC, SCE shall present evidence of its attempts to pursue optimal solutions to remediating overloaded joint poles, including removal of attachments or fair allocation of costs among joint pole users. SCE should consider the allocation of costs to each joint pole user in relation to the relative responsibility for the load on the joint poles. SCE should also quantitatively address the role of unauthorized attachments in pole

[310] D.98-10-058 at 76.

loading and discuss its efforts to minimize this impact. If SCE believes that a Commission proceeding including joint owners and renters as participants is necessary in order to achieve good results, SCE may propose a procedural approach; SCE does not need to wait for its next GRC to do so. To be clear, SCE and joint owners and renters should all recognize that we believe the costs of remediating overloaded joint poles should be allocated approximately in proportion to the causes of the overloading. SCE should seek to quantify the causes of pole loading, and attribute those causes among SCE, joint owners, and renters. Then, SCE should develop solutions to remediate overloading while avoiding an allocation of costs that results in SCE ratepayers bearing a disproportionate share. We encourage SCE and other interested parties to expeditiously address these issues.

We are neither reaching a conclusion that the proposed cost allocation advanced by SCE in this proceeding is not fair, nor that the best alternative is to remove any attachments. We are merely concluding that SCE has not adequately demonstrated that its proposal is reasonable.

Notwithstanding the guidance above, we believe it is important for SCE to continue the work of repairing and replacing overloaded poles via the PLP. SCE should not stop the PLP while seeking to achieve the improvements discussed above. Thus, we must turn to the question of what amounts to approve for capital expenditures at this time. In recognition of the concerns and guidance expressed above, we adopt lower PLP expenditures than SCE's request. SCE may wish to prioritize SCE-only pole replacements in the initial years of the PLP as well as poles in high wind and high fire areas.

For purposes of 2014 and 2015 capital expenditures, we adopt SCE's forecast of $844 (2012$) in credits per pole replaced. We recognize that this

number may grow in the future as SCE seeks to implement our guidance related to joint owners and renters.

Based on our analysis above, we are optimistic that SCE may be able to remediate additional overloaded poles per dollar of SCE ratepayer expense, either by removing attachments, strengthening existing poles, or achieving greater cost share contributions from joint pole owners and renters. This is a potential efficiency gain in the PLP. More poles remediated per dollar can be viewed, for purposes of our analysis of how many pole replacements should be funded by ratepayers now, as a reduction in the total number of poles to be replaced over the life of the program. SCE shall provide analysis of these potential efficiency gains in its next GRC.

Further, overlap between PLP and other programs may reduce the number of poles ultimately replaced by PLP. The parties acknowledge considerable uncertainty in the total number of poles to be replaced, particularly in their disagreement about the level of overlap between PLP pole replacements and other programs. One complication in our review of the parties' estimates of overlap is the different reference points, i.e. does a PLP replacement displace the need for a deteriorated pole replacement, or vice versa? We choose to view the overlap as reductions to the number of PLP replacements, noting that in Section 7.6.4.2 above, we approve SCE's proposed deteriorated pole replacements. Thus, there are two factors which may reduce the total number of poles to be replaced by PLP: non-replacement remediation and replacement by other programs, both of which we anticipate increasing over time.

We estimate an average annual replacement rate of 18,213 poles per year using the following values: 20% efficiency gain in the remediation of joint use poles (e.g., poles that can be remediated without replacement funded by SCE

ratepayers; increased cost share from joint owners or renters) and 12% of the poles to be replaced (at SCE ratepayer expense) will be replaced by other programs. The calculation of this estimate is shown in the table below, and the discussion of the estimated values follows. Our calculation uses the same approach advocated by ORA and TURN, based on the replacements spread evenly over the entire 11-year period.

	Item	Formula/Source	Number of Poles
1	Total Poles	SCE-76	1,423,101
2	Total Poles Replaced in SCE's PLP Proposal	SCE-3V6P2	268,688
3	70% Joint Use	0.7*Line 2	188,082
4	20% efficiency gain in joint pole remediation	0.2*Line 3	37,616
5	Total Poles to be Replaced by PLP, before Overlap	Line 2 - Line 4	231,072
6	12% of Poles to be Replaced by Other Programs	0.12*Line 5	27,729
7	Total Poles to be Replaced by PLP	Line 5 - Line 6	203,343
8	PLP Poles Replaced in 2014	SCE-3V6P2	3,000
9	Poles to be Replaced by PLP (2015 through 2025)	Line 7 - Line 8	200,343
10	Pole Replacements per year (2015 through 2025)	(Line 9)/(11 years)	18,213

No party explicitly advances an estimate for an efficiency improvement of joint pole remediation as funded by SCE ratepayers. As TURN points out, SCE's implicit assumption is zero improvement. SCE has not justified this assumption. The tone of TURN's argument suggests it foresees a much higher possible improvement, but TURN has not justified any particular value. We find 20% to be a reasonable starting point forecast in light of the known contribution of

attachments to overloading, the balancing account treatment adopted in Section 7.7.4 below, and the considerable uncertainty surrounding the total number of poles replaced.

Our estimate of 12% of overlap with other programs is approximately consistent with TURN's estimate (2,969/25,000 = 11.9%) of overlap, and is considerably lower than ORA's proposed 19%. This estimate strikes a reasonable middle ground between the likely limited overlap in the early years and the higher potential overlap in later years.

We approve SCE's forecast number of pole replacements for 2014. For 2015, we approve 18,213 replacements. SCE must apply for approval of 2016 and later years' capital expenditures in its next GRC. At our adopted unit costs (see Section 7.6.4.1 above), this results in capital expenditures as shown below.

Poles Per Year	2014	2015
Distribution	2,670	16,210
Transmission	330	2,003
Total	3,000	18,213
Millions of Nominal$		
Distribution	$32.899	$203.963
Transmission	$6.585	$41.043
Total	$39.485	$245.006

SCE, ORA, and TURN all recommend that the initial focus of PLP should be on high hazard areas. We agree, and direct SCE to focus its early PLP efforts on high hazard areas. In doing so, SCE should consider hazard maps developed in R.15-05-006 and other relevant information.

7.7.3.2. Other Expenditures Related to PLP

SCE forecasts several other categories of expenditures related to PLP: distribution transformers, prefabrication, and wood pole disposal. ORA disputes the amounts of these expenditures solely on the basis of its lower PLP pole

replacement forecast. There is no dispute among the parties about the relation between the pole replacement forecast and the forecast of these expenditures.[311] These relationships are undisputed and are reasonable. SCE also presents a forecast of PLP joint pole credits, which we discussed above in Section 7.7.3.1, and adopted SCE's forecast on a per pole basis. Thus, all that is needed to calculate our forecasts of these other expenditures is to apply the ratio of approved pole replacements to SCE's requested number of pole replacements. These ratios are shown below and the resulting forecasts are included in the summary table in Section 7.7.3 above.

Ratios Based on Pole Replacements	
2014	2015
1	0.729

7.7.4. Ratemaking for PLP

SCE proposes a PLP Balancing Account (PLPBA).[312] ORA proposes a 10% cap above authorized amount. TURN recommends including the deteriorated pole replacements, discussed in Section 7.6.4.2 above, in the PLPBA in order to address its concerns with the overlap between the programs. TURN clarifies that emergency pole replacements should not be recorded in the PLPBA.[313] TURN recommends a one-way balancing account, noting that the number of poles identified for replacement is the primary risk, but the PLPBA would protect SCE against all PLP risks (e.g., unit cost).[314] SCE supports addressing deteriorated poles in PLPBA.[315]

[311] SCE-19V6P2 at 17-20.
[312] SCE-3V1 and SCE-10V1P2.
[313] TURN-20 at 34-36.
[314] TURN OB at 91.
[315] SCE-19V6P1 at 43.

CUE supports the PLPBA. Further, CUE proposes an incentive mechanism to "deal with under-spending." CUE's mechanism would refund to ratepayers 110% of unspent money if SCE falls short of the target percentage for pole replacements by more than 10%. The target would be calculated as: (# poles approved for replacement through 2017)/(# poles expected to be identified as overloaded).[316] SCE rejects CUE's proposed incentive mechanism claiming that it unnecessarily duplicates existing incentives for SCE to replace poles, inappropriately constrains managerial discretion, and may have unintended consequences.[317] We agree with SCE that existing compliance requirements are sufficient and do not adopt CUE's proposal.

We approve SCE's request to create a PLPBA to track expenditures for poles replaced through both the PLP and the deteriorated pole program. The basic proposal is uncontested. Given the significant uncertainty in the number of poles involved, this balancing account appropriately reduces risk for both customers and investors. We adopt a variation on ORA's proposed 10% cap to further protect ratepayers, but except for that cap, we find that a two-way balancing account is appropriate. Specifically, we place a 15% cap on the 2016 and 2017 spending only, and do not impose any cap on 2015 spending in recognition of the timing of this decision.

7.7.5. Summary of Pole Replacements

Our total approved pole replacement rate for all programs is compared to SCE's request in the following table. Although our approved level of replacements is significantly lower than SCE's request, it is significantly higher than historical levels. Notably, this rate of replacement is below the equilibrium replacement rate assuming average service lives (ASLs) for distribution poles of

[316] CUE-1 at 27 and CUE OB at 38-40.
[317] SCE-3V6P1 at 59.

47 years and 50 years for transmission poles, as adopted in Section 21.2 below.[318] However, the increase in total pole replacements is a step toward achieving equilibrium, without going beyond the equilibrium replacement rate as proposed by SCE and CUE.[319] We recognize that an equilibrium replacement rate must be achieved in the future. Nevertheless, individual pole replacements should be based on testing, loading, or other pole-specific analysis, and options to extend pole life (and thus increase ASL) should be considered.

	SCE		Adopted	
	2014	2015	2014	2015
Aged Pole Replacements	14,500	1,898	9,000	0
Deteriorated Pole Replacements	7,600	8,102	7,600	8,102
Pole Loading Driven Pole Replacements	3,000	25,000	3,000	18,213
Total Poles Replaced Per Year	25,100	35,000	19,600	26,315
% Total Pole Replacements Adopted/Requested			78.1%	75.2%

7.8. T&D – Grid Operations

SCE's grid operations organization is responsible for several major activities:

1. Operate and monitor electrical facilities,
2. Provide storm and unplanned outage response, and
3. Inspect and maintain SCE's street lights and outdoor lighting.

SCE requests $115 million (2012$) in O&M and $99 million (nominal$) in capital expenditures for 2015.[320]

[318] 1.4 million poles replaced at 26,415 poles per year suggests an ASL of 53 years. An equilibrium replacement rate for the adopted ASLs would be approximately 29,000 poles per year.
[319] 35,000 poles replaced per year suggests an ASL of 40 years.
[320] SCE-3V7.

7.8.1. Grid Operations O&M

SCE forecasts O&M expenses in nine different FERC accounts, four of which are contested by ORA. The parties' forecasts[321] and our adopted forecast are summarized below (millions of 2012$).

Account	Activity	Requested	ORA	Adopted
561.170	Grid Control Center Operations	8.834	6.678	8.834
562.170	Transmission Substation Operations	18.667	18.667	18.667
573.170	Substation and Transmission Storm Expenses	1.536	1.536	1.536
582.170	Distribution Substation Operations	26.206	26.206	26.206
583.170	Troubleman Activities	32.665	31.336	32.665
585.170	Streetlight Expenses	8.763	8.763	8.763
587.170	Service Guarantees	0.489	0	0
588.170	Grid Operations Support	2.699	2.699	2.699
598.170	Distribution Storm Expenses	12.431	10.156	12.431
Total		112.291	106.041	111.801

7.8.1.1. GCC Operations (Account 561.170)

GCC has over 30 employees and three main responsibilities: operating and monitoring SCE's bulk power system, coordinating planned outages, and developing and maintaining operating procedures. SCE forecasts costs based on 2012 recorded costs per employee ($0.159 million), with a growth in number of employees from 31 to 41 from 2012 to 2015. SCE forecasts the ratio of labor to non-labor based on 2012 recorded.

SCE cites increases in the number of planned outages and in the amount of equipment in SCE's grid as justification for the increased number of employees. Further, SCE claims it must increase staffing to prepare for impending future retirements.[322]

[321] SCE-19V7 at 2.
[322] SCE-3V7 at 5-8.

ORA notes that SCE's request represents a 32.3% increase over 2012 recorded, and proposes to use 2012 recorded expenses. ORA states that 2012 is the highest recorded figure for this account in the last five years. Further, ORA claims that SCE was authorized additional staff in its recent GRCs and that recorded expenses do not reflect these positions being filled. ORA claims that SCE's arguments for increased GCC staffing in this case repeat arguments from past cases, but that SCE has not increased staffing and has incurred overtime and double-time costs. In conclusion, ORA states that SCE has sufficient staff and funding for GCC.[323]

In rebuttal, SCE notes that at the time of its direct testimony, it had already hired five of six positions authorized by D.12-11-051, and that by the time of its rebuttal it had hired four additional staff for a total of 39 employees. Therefore, SCE argues, ORA's forecast would not account for staff that was authorized by the last GRC decision. SCE also cites a NERC Standard (EOP-008-1) requiring it to maintain an Alternate GCC.[324]

We agree with SCE that ORA's forecast unreasonably discounts staffing increases that were previously approved. SCE's basic argument is reasonable: staffing must increase to accommodate increases in work due to the growing electric grid. We find reasonable and adopt SCE's forecast.

7.8.1.2. Storm Response (Accounts 573.170 and 598.170)

Storm O&M includes costs to manage the storm command center, identify affected facilities, assessments, isolation of problem areas, and repair of damaged equipment. SCE bases its forecast on a five-year recorded average, noting that this approach has been adopted in SCE's last three GRCs. Certain storm events

[323] ORA-9 at 36-30.
[324] SCE-19V7 at 3-4.

can be recorded in and recovered through a CEMA filing; such costs are removed from the storm response accounts.[325]

ORA proposes using a three-year (2010-2012) average for Account 598.170, accepts SCE's forecast for Account 573.170, and proposes that the two accounts be covered by a one-way balancing account. ORA's rationale is that SCE's forecast is unreasonably higher than 2012 recorded.[326]

SCE rejects ORA's forecast as unsupported and inconsistent with precedent.[327] We agree. SCE also rejects the asymmetric one-way balancing account treatment that would lead to ratepayer refunds in some years and would require shareholders to fund storm activities in other years.[328] We agree. ORA's arguments in this area have no merit. SCE's five-year average forecast method is reasonable given the inherent variability of storm expenses.

7.8.1.3. Troubleman/First Responder Activities (Account 583.170)

SCE refers to the first responders to service problems as troublemen. These first responders are highly trained in troubleshooting, switching, and emergency scene control. SCE employees responded to over 200,000 incidents in 2012, up 17% from 2009. SCE's forecast is based on increasing the number of troublemen/first responders from 185 in 2012 to 203 in 2015, and a 5% decrease in the cost per troubleman/first responder. SCE states that it has determined the increase in number of troublemen/first responders is necessary to achieve its goal for coverage of its service territory at peak and non-peak times. The increase in number will lead to a decrease in overtime costs.[329]

[325] SCE-3V7 at 14-17.
[326] ORA-9 at 33-34.
[327] SCE-19V7 at 6-7.
[328] SCE-26V1 at 22-23.
[329] SCE-3V7 at 20-22.

ORA bases its forecast on 2012 recorded expenses. ORA argues that 2012 recorded includes nearly $10 million in premium time "which can be reallocated for additional positions." ORA notes that its proposed forecast is greater than either the five-year or three-year recorded average.[330]

SCE responds that its forecast accounts for the anticipated reduction in overtime hours and that overtime can only be partially replaced by normal hours. SCE claims that ORA errs in assuming that the total hours worked will remain constant; SCE forecasts total hours worked to increase to meet its coverage goals.[331] SCE also claims that hiring additional troublemen/first responders will reduce safety risks associated with fatigue and reduce the time to restore service following an outage.[332]

We find SCE's forecast reasonable and adopt it. The amount of overtime identified by ORA is less than half the cost of 18 additional troublemen/first responders. SCE's argument that overtime can only be partially replaced by normal hours is reasonable. Further, we agree with SCE that there are potentially significant safety and reliability benefits from additional troublemen/first responders.

7.8.1.4. Streetlights (Account 585.170)

SCE subdivides its forecast into two components. For the inspection and maintenance portion, SCE 2012 recorded costs per streetlight times the number of forecast streetlights. For the operations and billing portion, SCE bases its forecast on 2012 recorded values.[333]

Cal-SLA supports SCE's forecasts for Account 585.170, but also recommends that we require SCE "to correct streetlight inventory errors and

[330] ORA-9 at 31-32.
[331] SCE-19V7 at 8-9.
[332] SCE-15 at 42.
[333] SCE-3V7 at 22-26.

provide customer refunds within three months after the customer notifies SCE of the error."[334] We discuss this issue in Section 7.8.2.2.1 below.

We find reasonable and adopt SCE's uncontested forecast for Account 585.170.

7.8.1.5. Service Guarantees (Account 587.170)

SCE provides two T&D related service guarantees to its customers: 1) restore power within 24 hours of learning of an unplanned outage, and 2) provide three day advance notice of any planned outages to affected customers. Currently, the guarantee payouts ($30 per incident to each impacted customer) are shareholder funded. SCE argues that all customers benefit from the guarantee program because it motivates SCE to meet commitments to customers, and therefore concludes that ratepayers should fund a baseline level of payouts. SCE proposes 2012 recorded payouts for this baseline, the lowest level in the five-year recorded period. SCE attributes a decrease in recorded guarantee payouts over recent years to improvements in its customer outage notification process.[335]

ORA cites prior GRC decisions rejecting ratepayer funding for guarantee payouts and recommends that we continue that policy.[336] As we found in D.12-11-051, we agree with ORA that SCE has not presented a persuasive argument for ratepayer funding of service guarantees. Therefore, we reject SCE's proposal.

7.8.1.6. Uncontested Accounts

SCE bases its forecast for Substation Operations (Transmission in Account 562.170 and Distribution in Account 582.170) on 2012 recorded costs per

[334] Cal-SLA-1 at 3-5.
[335] SCE-3V7 at 32-34.
[336] ORA-9 at 32-33.

employee with two adjustments. SCE anticipates a 3% reduction in cost per employee and a slight increase in the number of employees, for a small net increase in total costs. The extra cost of staff is offset, partly, by reduced overtime expenses.[337] We find reasonable and adopt SCE's forecasts for these accounts.

Cal-SLA supports SCE's forecasts for Account 585.170.

We also find reasonable and adopt SCE's forecasts for the remaining uncontested accounts.

7.8.2. Grid Operations Capital

SCE's forecast is divided into three areas: storm, streetlights, and operational facilities maintenance. Our adopted forecast is summarized below.

(millions of nominal$)		2014	2015
Storm		$ 47.084	$ 48.110
	Transmission	$ 4.562	$ 4.683
	Substation	$ 0.316	$ 0.325
	Distribution	$ 42.206	$ 43.102
Streetlights		$ 38.872	$ 36.564
	Pole Replacement	$ 24.505	$ 25.025
	Luminaire Replacement	$ 12.273	$ 9.400
	Breakdown Maintenance	$ 2.094	$ 2.139
Operational Facilities Maintenance		$ 5.600	$ 5.749
Total		$ 91.556	$ 90.423

7.8.2.1. Storm

Storm capital expenditures are all expenditures to replace facilities, structures, and equipment damaged in storm events, excluding those events for which costs are recovered through a CEMA filing (as discussed for Storm O&M in Section 7.8.1.2 above). SCE subdivides its forecast into three components: transmission, substation, and distribution. SCE uses five-year recorded averages

[337] SCE-3V7 at 8-14.

for its forecast.[338] ORA accepts SCE's forecasts for this area.[339] We find SCE's five-year average forecast reasonable and adopt it.

7.8.2.2. Streetlights

Streetlight capital expenditures are grouped into three categories: steel pole replacements, luminaire replacements, and breakdown maintenance.

SCE states that it has an ongoing program to replace steel streetlight poles with concrete poles due to age and corrosion, and anticipates replacing all 70,000 poles by 2025. SCE describes three mechanisms for pole failure, all related to corrosion: rust at top of pole, holes at bottom due to rust, and rusty anchor bolts. SCE suggests that poles near the ocean corrode more rapidly than others. SCE initially forecast 5,500 pole replacements in 2014 and 5,000 in 2015 at a unit cost of $6,300 (2012$).

SCE states that "typically" luminaires last about 15 years. SCE forecasts replacement of 40,000 luminaires in 2014 and 30,000 in 2015 at a unit cost of $300 (2012$).

SCE forecasts $2 million (2012$) per year of breakdown replacements based on 2012 recorded data.[340] SCE's revised total forecast is $50.251 million in 2014 and $44.853 million in 2015 (nominal$).[341]

ORA recommends a lower pole replacement rate. ORA notes that SCE's proposed 2013-2015 annual expenditures is more than three times the annual average of 2009-2012. For pole replacements, ORA calculates a 433% increase in the average number of poles replaced in SCE's forecast compared to 2008-2012. ORA claims that all poles near the ocean have been already been replaced. ORA asserts that SCE does not select poles for replacement based on specific

[338] SCE-3V7 at 17-19.
[339] ORA OB at 135.
[340] SCE-3V7 at 26-28.
[341] SCE OB at 143.

engineering analysis, instead replacing all poles based on location. Further, ORA claims that SCE does no maintenance other than painting poles, does not maintain maintenance records, and could not verify the age of poles. ORA recommends that 2012 authorized expenditures should be escalated for inflation and that SCE should not be allowed to accelerate the replacement rate before conducting additional analysis.[342]

TURN submits that SCE has not justified the need to replace all steel poles and recommends $5.661 million (2012$) for each of 2014 and 2015. TURN suggests that SCE's recent experience of observing corroded anchor bolts in 80% of poles replaced during 2005-2013 is due to SCE's focus on replacing poles near the ocean. TURN suggests that this focus is appropriate and that corrosion in poles near the ocean does not establish likelihood of corrosion of inland poles. Further, TURN suggests that SCE should institute a testing program and discounts several arguments from SCE (raised in cited discovery responses) that such testing is inappropriate, ineffective, or infeasible. Finally, TURN notes that SCE has not recorded pole-replacement locations relative to the ocean or documented its concerns about corrosion attributable to sprinklers. TURN initially concluded that SCE should only replace poles within five miles of the ocean without further analysis, and estimated that a replacement rate of 948 poles per year is adequate to complete this task by 2017. TURN recommends that we require SCE to develop a cost-effective testing program or provide evidence to support that such a method is not available.

TURN also disputes SCE's proposed unit cost and recommends $5,972/pole (2012$) based on recorded data from 2013 and part of 2014.[343]

[342] ORA-12 at 22-25.
[343] TURN-03 and TURN-3A at 38-43.

In its brief, TURN revises its conclusion to recommend replacing poles up to ten miles from the ocean and calculates a higher corresponding forecast based on a replacement rate of 3,620 per year. TURN cites data that show only 2% of bolts in a city greater than ten miles from the ocean suffered severe corrosion and generally suggests an inverse correlation between distance and severe corrosion.[344]

Cal-SLA supports SCE's capital forecast.[345]

CASL suggests that methodological changes in SCE's accounting and forecasting make it difficult to understand the justification for SCE's forecast. CASL discusses the change in how SCE developed its unit costs in this GRC (cost per pole includes other components, e.g., conductor) versus the 2012 GRC (individual unit costs for poles and conductor). CASL calculates that, on a comparable basis, unit costs have doubled relative to SCE's 2012 request. CASL also finds confusion in SCE's historic steel pole replacement quantity records, and provides an example of the number of poles replaced in 2005, reported as three different numbers, ranging from 840 to 2,050, in the 2009 to 2015 GRCs. In conclusion, CASL recommends that we require SCE to develop a plan for better recording, presenting and analyzing costs and to be consistent in how it estimates costs in future GRCs.[346]

CASL also proposes changes to SCE's forecast of CIAC.[347] SCE accepts these changes in rebuttal.[348]

SCE suggests that proposals to delay or slow the replacement program are without merit because of "age of the poles and the fact that the vast majority of

[344] TURN OB at 113-120 and TURN-88.
[345] SCE and Cal-SLA Settlement Agreement, discussed in Section 27.2 below.
[346] CASL-1 at 3-9.
[347] CASL-1 at 9-10.
[348] SCE-19V7 at 26.

poles have heavy to very severe corrosion." Further, SCE contends that inspections and testing are costly and unnecessary based on its belief that the findings would corroborate SCE's postmortem inspections (i.e., 84% of replaced poles have corroded anchor bolts). SCE claims that ORA's proposal would slow replacements to 2,000 per year, leading to a 30-year replacement schedule. SCE claims that of 2014 (part year) replacements "most" have occurred in cities more than five miles from the ocean, and that 75% of the 4,000 poles replaced had two or more (of four) anchor bolts with heavy to severe corrosion and 86% with at least one corroded anchor bolt.

Although SCE considers it a moot point, SCE calculates that it will have over 10,000 steel poles remaining in service within five miles of the ocean at the end of 2014, considerably higher than TURN's estimate of 3,300.

SCE also rejects CASL's concerns about unit costs, noting that its 2012 GRC forecast incorrectly excluded contractor labor, resulting in a significantly lower unit cost. SCE notes that recorded costs in 2013 and 2014 (part year) were $6,171 and $6,147 respectively. SCE accepts slightly lower unit costs ($6,230/pole; $293/luminaire) than proposed in its original testimony.

Finally, SCE contends that its record keeping is in compliance with applicable regulations and SCE's past commitments. SCE describes that it has many work orders related to streetlight property accounts and that to answer all of the questions posed by CASL would require manually retrieving information from each in order to meet CASL's "onerous" request. SCE volunteers to supply work order data to CASL or to arrange to do the analysis at CASL's expense.[349]

[349] SCE-19V7 at 16-25.

7.8.2.2.1. Discussion – Streetlight Data Quality and Transparency

CASL and TURN point to significant problems in SCE's recorded data and inconsistencies in SCE's forecast approach that hinder transparency. SCE's responses to these concerns are inadequate in many cases. For example, SCE offers no substantive response to CASL's point about inconsistent records of how many poles have been replaced in past years. Similarly, the range of parties' initial estimates of steel poles remaining within five miles of the ocean varied widely, indicating a major dispute on an issue for which there should be little dispute with appropriate data and transparency. This issue may be a symptom of the same concern alleged by Cal-SLA about inventory errors (Section 7.8.1.4 above).

We are also sympathetic to SCE's point that producing detailed analysis or data on issues not directly tracked in its systems may be costly. Accordingly, we do not place any specific requirements on SCE for improved data tracking, but instead take these shortcomings into account in our review of the substantive issues below, remind SCE that it bears the burden of proof in GRCs, and observe that needless inconsistencies in how forecasts are developed (or data is recorded) from GRC to GRC may cast doubt on its showing.

7.8.2.2.2. Discussion – Streetlight Forecast

We agree with TURN that using recently recorded data is valuable to calculate unit costs for steel pole replacements due to the inconsistency in how the numbers have been developed in recent GRCs. However, TURN and SCE present different numerical values for the recorded average unit cost over 2013 and part of 2014, with no discussion of the differences. We adopt a unit cost of

$6,000/pole replacement (2012$), which is in the range of the values presented by the parties.

SCE has not presented adequate analysis or support to justify its proposed replacement of all 70,000 steel poles. SCE's primary reasons for the program are the age and condition of the poles. However, SCE does not provide compelling support based on either factor. SCE does not present any analysis of the age of the poles. Data in TURN-88, supplied by SCE, does not support SCE's conclusion, that all poles, even those greater than ten miles from the ocean suffer high rates of corrosion. On the contrary, the evidence suggests that low percentages of inland poles suffer significant corrosion. Whether through testing, additional postmortem analysis, or some other method, SCE must provide more persuasive analysis or data to receive approval of the entire steel pole replacement program. We leave the method for producing this additional support, in a future GRC, to SCE's discretion.

In comments on the Proposed Decision, SCE rejects this analysis and highlights the data on poles in the City of Whittier. While Whittier is a relevant example, this is anecdotal evidence; Whittier is not a representative sample of SCE's inland pole population.

Like TURN, we find that the data provided from SCE's recent postmortem analysis suggest that poles within ten miles of the ocean are likely corroding. Therefore, we adopt TURN's final proposal for unit counts, with a slight increase recognizing that poles in Whittier also experience high levels of corrosion.

We accept SCE's rebuttal proposal for luminaire unit costs of $293 (2012$) and SCE's uncontested forecast for the number of luminaires. Similarly, we adopt SCE's uncontested forecast for breakdown maintenance. The following table summarizes our adopted streetlight capital forecast.

		2014		2015	
		SCE	Adopted	SCE	Adopted
Pole Replacement (Millions of 2012$)		$34.265	$23.400	$31.150	$23.400
	Unit Cost (2012$)	$6,230	$6,000	$6,230	$6,000
	Units	5,500	3,900	5,000	3,900
Luminaires (Millions of 2012$)		$11.720	$11.720	$8.790	$8.790
	Unit Cost (2012$)	$293	$293	$293	$293
	Units	40,000	40,000	30,000	30,000
Breakdown Maintenance (Millions of 2012$)		$2.000	$2.000	$2.000	$2.000
Total	Millions of 2012$	$47.985	$37.120	$41.940	$34.190
	Millions of nominal$	$50.250	$38.872	$44.853	$36.564

7.8.2.3. Operational Facilities Maintenance

Operational Facilities maintenance includes repairing or replacing failing substation facilities including buildings, climate control systems, tanks, fences, and gates. This maintenance is necessary for safety of employees and to protect sensitive electrical equipment. SCE states that many substation facilities require increasing amounts of maintenance work due to increasing age. SCE further states that spending began increasing in 2012 as it began to focus on this maintenance of aging facilities. SCE anticipates a major upgrade at Santa Clara Substation and ongoing upgrades related to operators' situational awareness to further increase costs to 2014 and to maintain that level going forward. SCE's forecast is $5.600 million in 2014 and $5.749 million in 2015 (nominal$).[350] ORA stipulates to SCE's forecast.[351] We find reasonable and adopt SCE's forecast.

7.9. T&D – Transmission & Substation Maintenance

This chapter addresses forecasts for: inspection and maintenance of transmission and subtransmission lines and substations, including activities such

[350] SCE-3V7 at 34-35.
[351] ORA-57R.

as vegetation management and transmission line rating remediation. SCE requests $86 million (2012$) in 2015 O&M and $686 million (nominal$) of capital expenditures (2013-2017), of which $418 million is CPUC-jurisdictional.[352] ORA contests many of SCE's forecasts.

7.9.1. O&M

ORA proposes a forecast $8.408 million lower than SCE's, contesting several elements of SCE's forecast. Two Accounts (562.150 and 582.150), both recording work performed by other parts of SCE's organization are uncontested. We find these uncontested forecasts reasonable. Our approved forecast is summarized below.

[352] SCE OB at 149.

Account	Activity	SCE	Adopted
562.150	Work Performed by Others	$ 1.282	$ 1.282
582.150	Work Performed by Others	$ 0.164	$ 0.164
566.150	Overhead Inspections and Patrols	$ 4.337	$ 4.337
	Transmission Line Rents	$ 15.351	$ 15.351
	Line Expenses	$ 2.960	$ 2.960
	Intrusive Pole Inspection	$ 0.829	$ 0.829
	Underground Inspections	$ 1.163	$ 1.163
	Total	$ 24.640	$ 24.640
568.150	Circuit Breaker Inspection and Maintenance	$ 2.855	$ 2.855
	Relay Inspection and Maintenance	$ 3.664	$ 3.463
	Transformer Inspection and Maintenance	$ 1.563	$ 1.563
	Miscellaneous Equipment	$ 3.135	$ 3.135
	SSID Maintenance	$ 1.910	$ 1.910
	Maintenance Crew Supervision	$ 2.390	$ 2.390
	Total	$ 15.517	$ 15.316
592.150	Circuit Breaker Inspection and Maintenance	$ 3.722	$ 3.722
	Relay Inspection and Maintenance	$ 1.627	$ 1.627
	Transformer Inspection and Maintenance	$ 1.386	$ 1.386
	Miscellaneous Equipment	$ 3.795	$ 3.795
	Miscellaneous Substation Maintenance	$ 0.447	$ 0.447
	Maintenance Crew Supervision	$ 2.699	$ 2.699
	Total	$ 13.676	$ 13.676
571.150	Insulator Washing	$ 5.678	$ 5.678
	Road and Right of Way Maintenance	$ 9.161	$ 9.161
	Vegetation Management	$ 4.345	$ 4.345
	Vegetation Management - Big Creek	$ 2.158	$ 1.079
	Overhead and Underground Maintenance	$ 6.019	$ 6.019
	Line Rating Remediation	$ 3.379	$ 3.379
	Total	$ 30.740	$ 29.661
Total		$ 86.019	$ 84.739

7.9.1.1. Transmission Line Inspection (FERC Account 566.150)

SCE's total forecast for this subaccount is $24.640 million (2012$), composed of: Line Expenses, Overhead Inspections and Patrols, Intrusive Pole Inspections, Line Rents, and Underground Inspections. Of these, ORA contests Overhead Inspections and Patrols and Line Rents, for a total forecast of $24.354 million.

Overhead Inspections are performed at least annually to comply with GO 165 and are approved by CAISO. SCE's forecast is based on a 5YA cost per mile multiplied by the forecast number of miles of transmission lines.[353] ORA accepts the cost per mile, but disputes SCE's forecast of increased miles of transmission lines. ORA notes that the actual increase during 2013 was 51 miles compared to SCE's forecast of 301 and that some of the added line miles are related to projects rebuilding existing lines. ORA uses a five-year recorded average of increased line miles to calculate its forecast.[354] In response, SCE notes that its forecast of line miles is based on specific projects that it is constructing, claims that it expects these lines to go into service in 2014 or 2015, and explains that rebuilt lines are replacing out of service lines or adding double circuits in place of single circuit lines.[355] We find SCE's explanation of rebuilt lines reasonable. Further, SCE's forecast of line miles based on specific construction projects is superior to a forecast based on historical averages. SCE's forecast of Overhead Inspections and Patrols is reasonable and is adopted.

Transmission line rents are paid to public and private landowners, including the U.S. Forest Service, for use of property for transmission lines. SCE forecasts an increase due to a new line rent for a line through the Morongo

[353] SCE-3V8 at 1-7.
[354] ORA-8 at 39-41.
[355] SCE-19V8 at 4.

Indian Reservation. Further, SCE forecasts 1.9% increase per year for rent increases.[356] ORA disputes SCE's proposal to levelized 2015-2017 expenses to develop its test year forecast. ORA argues that the attrition mechanism provides for these type of increases.[357] As we discussed in Section 7.5.1 above, the Results of Operations model used in preparation of this decision does not escalate this cost. Therefore, we adopt SCE's proposed test year forecast.

The remainder of SCE's forecast for this account is uncontested, and is approved.

7.9.1.2. Transmission Line Maintenance (FERC Account 571.150)

7.9.1.2.1. Insulator Washing and Road and Right of Way Maintenance

For each of these forecasts, SCE applied a 5YA cost per mile to its forecast of line miles.[358] In both cases, ORA accepts SCE's cost per mile, but uses its lower line mile forecast.[359] As discussed in Section 7.9.1.1 above, we adopt SCE's line mile forecast. SCE's five-year averages are undisputed. Therefore, we adopt SCE's forecasts for these areas.

7.9.1.2.2. Transmission Vegetation Management

SCE uses 2012 recorded costs plus an additional forecast of the Big Creek area. SCE describes past challenges in managing trees in the mountainous Big Creek area, and states that it is launching a new effort to manage vegetation along the lines in September 2013. SCE will begin with highest risk areas. SCE argues that this proactive management is necessary under NERC regulations (NERC-FAC-003-2). SCE bases its forecast on contract costs from its bark beetle

[356] SCE-3V8 at 18-19.
[357] ORA-8 at 49-50.
[358] SCE-3V8 at 14-16.
[359] ORA-8 at 42-44.

program, which involves similar activities. SCE's forecast is $2.158 million, all non-labor.[360] SCE's total transmission vegetation management forecast is $6.503 million, with the remaining $4.345 million representing based on 2012 recorded values.[361]

ORA accepts the 2012 recorded costs as a basis for 2015 forecast, but contests the Big Creek forecast. ORA contends that this project had not begun by March 21, 2014, and SCE did not have permits to begin. ORA proposes a forecast of $4.345 million based on recorded 2012 expenses, stating that SCE is not ready to begin the Big Creek project and that SCE has "embedded" funding to complete this work if it receives permits.[362]

SCE responds that it has obtained permission from private landowners to start work, expects to receive permits during 2014, and does not change its test year forecast.[363]

We agree with ORA that possible further permitting delays suggest a decrease to SCE's forecast. However, given that SCE has permission to start work from private landowners, we decline to reduce SCE's request to zero. Instead, we approve 50% of SCE's Big Creek request and all of the other transmission vegetation management. Thus, we approve a total forecast as shown below (2012$, millions).

Base Expenses		Requested	Adjustment	Approved
	Labor	$ 0.066		$ 0.066
	Non-Labor	$ 4.279		$ 4.279

[360] SCE-3V6P1 at 21-23.
[361] SCE-03V8 at 17-18.
[362] ORA-8 at 44-48.
[363] SCE-19V6P1 at 11.

	Total	$ 4.345		$ 4.345
Big Creek				
	Non-Labor	$ 2.158	$ (1.079)	$ 1.079
Total Expenses				
	Labor	$ 0.066		$ 0.066
	Non-Labor	$ 6.437	$ (1.079)	$ 5.358
	Total	$ 6.503	$ (1.079)	$ 5.424

7.9.1.2.3. Transmission Overhead and Underground Maintenance

SCE forecasts these maintenance costs on the basis of a five-year average, after subtracting out the cost of significant programmatic maintenance performed during 2009-2010.[364] This forecast is uncontested, and we find it reasonable.

7.9.1.2.4. Transmission Line Rating Remediation

SCE has undertaken a study of line clearance requirements and prioritized its lines for remediation, including replacing towers, clearing brush, replacing insulators, and removing slack from lines. A high percentage of expenses are subject to FERC jurisdiction. SCE's forecast is based on specific projects, levelized from 2015 to 2017.[365] ORA contends there is insufficient evidence to justify these expenses, noting that there were no expenses prior to 2013 and claims that SCE was unable to identify 2013 recorded on a comparable basis to its request. To develop its forecast, ORA removes all FERC-jurisdictional costs and does not levelize costs over three years.[366] In response, SCE notes that GRC costs

[364] SCE-3V8 at 12-14.
[365] SCE-3V8 at 20-21.
[366] ORA-8 at 50-52.

are presented on a total company basis.[367] We find that SCE's forecast is reasonable and adopt it, consistent with our finding that SCE's jurisdictional allocation factors are reasonable in Section 15 below.

7.9.1.3. Substation Inspection and Maintenance (FERC Accounts 568.150 and 592.150)

7.9.1.3.1. Circuit Breaker Inspection and Maintenance

SCE explains that substation circuit breakers are complex and require routine maintenance, including both prescriptive and condition-based maintenance. SCE performs periodic inspections of a variety of types. SCE's forecast is based on a 5YA of recorded costs per breaker times its forecast of circuit breakers.[368] ORA claims that SCE "vastly overstated" the number of new circuit breakers in 2013 and that the number of breakers actually decreased rather than increased. ORA proposes a lower forecast of the number of breakers, but accepts SCE's unit costs. ORA notes that its forecasts are greater than the five-year averages.[369] SCE asserts that ORA inappropriately relied on numbers of inspections performed in 2013 rather than the number of breakers actually on the system. SCE contends its forecast of additional breakers is based on specific projects and should be relied on rather than historical averages.[370] SCE's forecast, based on specific projects, is reasonable and should be adopted.

7.9.1.3.2. Transformer Inspection and Maintenance

SCE notes that transformers are among the most expensive and critical pieces of equipment. SCE's forecast is based on a 5YA cost per transformer times

[367] SCE-19V8 at 9.
[368] SCE-3V8 at 22-23.
[369] ORA-8 at 53-57.
[370] SCE-19V8 at 10-11.

the forecast number of transformers.[371] ORA contends that SCE overstates the number of distribution transformers, and calculates a lower value based on the average rate of change (2008-2013) and applying this to 2013 recorded. ORA accepts SCE's cost per transformer and number of transmission transformers.[372] As above, SCE notes that ORA incorrectly relied on the number of inspections in 2013 rather than the number of transformers.[373] SCE's forecast, based on specific projects, is reasonable and should be adopted.

7.9.1.3.3. Relay Inspection and Maintenance

SCE implemented a new maintenance program in 2011 that focuses on relays, among other components, in response to a new NERC standard. SCE contends this standard drives up documentation costs. SCE also foresees needing to install cyber security patches in response to future standards. SCE's forecast is based on 2012 recorded unit costs times forecast number of inspections. SCE forecasts 1,258 transmission inspections in 2015 at a cost of $2,447 each.[374] ORA disputes the number of inspections, noting that there has been a decrease from 2008 to 2012 and that SCE's 2013 recorded is 300 inspections lower than 2013 forecast. ORA claims SCE had "ample funding" from the last GRC to complete relay inspections and that current ratepayers should not be charged for deferred maintenance. ORA forecasts 779 inspections, based on a 2011-2013 average. ORA proposes to remove costs for FERC jurisdictional expenses. ORA accepts SCE's forecast for distribution relays.[375] SCE calculates that it must complete 1,575 inspections per year during 2014-2016 to meet compliance obligations. SCE claims that it defines deferred maintenance based

[371] SCE-3V8 at 24-26.
[372] ORA-8 at 56-58.
[373] SCE-19V8 at 12-13.
[374] SCE-3V8 at 28-30.
[375] ORA-8 at 58-62.

on meeting (or missing) regulatory deadlines, not internal schedules, and that it is on track to meet 2016 compliance obligations. SCE notes again that all costs are presented on a total company basis.[376] We accept SCE's uncontested distribution forecast. However, for transmission relay inspections, we agree with ORA that SCE has not adequately justified its proposed level. We base our forecast on 1,178 relays per year, the rate needed to actually levelize inspections over the six-year period identified by SCE. We find reasonable and approve SCE's uncontested forecast of NERC/CIP-related relay work. Our adopted forecast for transmission relays (Account 568.150) is shown below (millions of 2012$).

Total	$ 3.463
Labor	$ 2.874
Non-Labor	$ 0.589

7.9.1.3.4. Uncontested Forecasts

SCE's forecasts for SSID maintenance costs, miscellaneous substation expenses, miscellaneous equipment inspection and maintenance,[377] and maintenance crew supervision are uncontested. We find SCE's forecasts for these activities reasonable.

7.9.2. Capital

SCE's total 2014-2015 capital forecast is $262.577 million (nominal$), while ORA recommends $192.226 million. ORA calculates that SCE is requesting an 80% increase in 2015 over 2012 expenditures. For many components of this forecast, ORA accepts SCE's 2013-2015 total forecast, but proposes adjustments to 2014-2015 based on SCE's 2013 recorded expenditures, in order to keep the total 2013-2015 amount equal to SCE's original application request. SCE opposes these

[376] SCE-19V8 at 14-15.

[377] ORA initially contested the miscellaneous equipment inspection and maintenance forecasts, but stipulated to SCE's forecasts in ORA-57R.

adjustments, claiming that 2013 expenditures over the forecast do not reduce the need for later expenditures. Many of the relevant expenditures are for unplanned work. SCE cites several instances in the 2014 PG&E GRC decision wherein we rejected similar adjustments proposed by ORA.[378] Generally, we uphold that precedent and find that, in the case of unplanned work, there is no clear inverse relationship or anti-correlation between amounts spent in one year and later years. Stated differently, overspending in 2013 does not indicate that lower expenditures are appropriate for 2014-2015. ORA appears to assume that short-term reversion to the mean should be expected, but provides no evidence for this assumption. We briefly address several subjects for which ORA makes this argument below. ORA's proposed adjustments on this basis are rejected. However, in other areas, such as replacing long lasting tools and equipment, it is reasonable to expect that increased spending in one year would lead to decreased expenditure needs in the immediately following years.

Our adopted capital forecast is summarized below.

Activity	SCE			Adopted		
	2014	2015	2014-15	2014	2015	2014-15
Transmission Capital Maintenance	$10.587	$10.869	$21.456	$10.587	$10.869	$21.456
Transmission Relocation	$25.218	$26.088	$51.306	$25.218	$26.088	$51.306
Transmission Claims	$2.305	$2.366	$4.672	$2.305	$2.366	$4.672
Transmission Line Rating Remediation	$24.183	$28.575	$52.757	$24.183	$28.575	$52.757
Transmission Spare Parts	$0.104	$0.107	$0.211	$0.104	$0.107	$0.211
Transmission Tools and Work Equipment	$1.524	$1.558	$3.082	$0.497	$0.508	$1.005
Substation Capital Maintenance	$37.797	$38.803	$76.600	$37.797	$38.803	$76.600
Online Transformer	$2.347	$5.911	$8.258	$2.347	$5.911	$8.258

[378] SCE-19V8 at 16-19 and ORA-12 at 27-28. .

Monitoring						
Substation Protection and Control Replacements	$12.009	$16.511	$28.520	$12.623	$12.533	$25.156
Substation Claims	$0.483	$0.494	$0.977	$0.483	$0.494	$0.977
Substation Spare Parts	$3.367	$3.442	$6.809	$3.367	$3.442	$6.809
Substation Tools and Work Equipment	$3.920	$4.010	$7.930	$2.125	$2.170	$4.295
Total	$123.844	$138.734	$262.578	$121.636	$131.865	$253.502

7.9.2.1. Transmission Capital Maintenance

This topic includes the costs to remove, replace and retire assets on both a programmatic and reactive basis. SCE's forecast includes three sub-categories: reactive, planned, and additional programmatic work. SCE uses a 5YA for reactive and 2012 recorded for planned. SCE forecasts an additional $7.5 million for replacement of switches, cable, vaults, and potheads as well as road work during 2013.[379] ORA recommends adjusting 2014-2015 downward to account for expenditures over forecast in 2013.[380] ORA has shown no reason that the 2014-2015 forecast for this category should be adjusted based on 2013. SCE's forecast of variable reactive work appropriately uses a five-year average. Its forecast of more predictable planned work appropriately uses 2012 recorded. SCE's forecast of the additional programmatic work is uncontested. SCE's forecast for reactive and planned work transmission capital maintenance work is reasonable. We adopt SCE's forecast.

7.9.2.2. Transmission and Substation Claims

SCE presents these as two separate categories. Transmission claims cover casualty damages such as cars hitting poles. These are random in nature. Substation claim expenditures replace or repair casualty damage, including

[379] SCE-3V8 at 40-41.
[380] ORA-12 at 29.

copper theft, and vary significantly year to year. SCE used a 5YA for each of these items.[381] ORA proposes to reduce 2014-2015 on the basis of overspending in 2013. ORA's proposal is illogical in context of the random nature of these claims. SCE's five-year average forecasts of transmission and substation claims are reasonable and is adopted.

7.9.2.3. Transmission Line Rating Remediation

This category includes replacing towers, clearing brush, and other efforts to remediate clearance requirements. SCE's forecast is project based.[382] ORA proposes to accept SCE's three-year forecast and reduce 2014-2015 on the basis of overspending in 2013.[383] In response, SCE notes that 2013 recorded was actually below 2013 forecast and that its revised forecast for 2013-2015 is actually lower than the original amount that ORA proposes to adopt.[384] ORA's premise is inaccurate in this instance. SCE's forecast of line rating remediation is reasonable and is adopted.

7.9.2.4. Transmission Relocations

Relocations involve moving existing facilities in response to requests from public or private entities. SCE's forecast is based on specific projects anticipated, and SCE expects significant growth in expenditures. Over 80% of forecast expenditures are customer funded.[385] ORA recommends that 2013 recorded values, adjusted for inflation, be used for 2014-2015 forecast. In support of this, ORA claims that SCE did not identify any projects starting after 2013.[386] In rebuttal, SCE provides its updated schedule, including specific projects through

[381] SCE-3V8 at 43-44 and 52-53.
[382] SCE-3V8 at 44-45.
[383] ORA-12 at 31-32.
[384] SCE-19V8 at 23-24.
[385] SCE-3V8 at 42-43.
[386] ORA-12 at 30.

2015. Further, SCE cites two factors increasing relocations: federal transportation legislation (MAP-21) and increasing residential development.[387] SCE provided a reasonable, project-based forecast of these expenditures, and ORA does not present a persuasive rationale not to adopt this forecast. SCE's forecast is adopted.

7.9.2.5. Transmission Tools and Work Equipment

Portable tools and equipment in this category cost more than $1,000, such as generators and cable pulling equipment that have relatively long lives. SCE uses 2012 recorded cost as the basis of its forecast noting that transmission work has increased since 2008 and that it expects the level of work to remain high, necessitating more tools.[388] ORA proposes to accept SCE's three-year forecast and reduce 2014-2015 on the basis of overspending in 2013. ORA notes that as of May 2014, SCE's annualized spending was below ORA's forecast.[389] In rebuttal, SCE repeats its arguments about precedent and claims that ORA's proposal does not consider safety impacts.[390] In this case, we find that SCE has not met its burden of proof. For the long lasting equipment contemplated here, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the immediately following years. Preliminary 2014 recorded information cited by ORA is consistent with that expectation. We find ORA's 2014-2015 forecast reasonable and adopt it.

7.9.2.6. Substation Capital Maintenance

This category includes costs to replace assets on a reactive or programmatic basis. SCE cites two reasons for recent increases in expenditures:

[387] SCE-19V8 at 21.
[388] SCE-3V8 at 46-47.
[389] ORA-12 at 32-33.
[390] SCE-19V8 at 25-26.

increasing programmatic maintenance and increasing reactive replacements due to aging infrastructure. SCE anticipates these increases continuing, and therefore used 2012 recorded to develop its forecast.[391] ORA notes that SCE's forecast was developed in three parts. For two of the component parts, ORA adjusts 2014-2015 down on the basis of 2013 overspending. For the remaining part, ORA recommends using 2013 recorded for 2014-2015.[392] SCE observes that ORA's method is inconsistent and not factually supported.[393] We agree with SCE that ORA's forecast is baseless. SCE's forecast of substation capital maintenance is reasonable and is adopted.

7.9.2.7. Online Transformer Monitoring

SCE proposes this program to monitor dissolved gas and bushings in transformers in order to provide a more cost-effective means to identify equipment in need of repair or replacement and reduce in-service failures. SCE's forecast is based on its installation plans.[394] ORA recommends disallowing CPUC-jurisdictional expenditures until SCE provides "concrete evidence" that this program benefits ratepayers. ORA notes that SCE has not included any savings in its forecast for this program, despite an estimated five-year payback time.[395] SCE notes that in exhibit ALJ-1, SED staff suggests that predictive maintenance, such as this program may be valuable means of reducing risk. Further, SCE notes that the business case prepared by its consultants suggests that this monitoring may allow SCE to maximize transformer life and that a single year of additional transformer life is sufficient to pay for monitoring of that transformer.[396] SCE's arguments that transformer monitoring is cost effective are

[391] SCE-3V8 at 47-48.
[392] ORA-12 at 33-34.
[393] SCE-19V8 at 27-29.
[394] SCE-3V8 at 49-50.
[395] ORA-12 at 35.
[396] SCE-19V8 at 30-31.

persuasive. SCE's forecast of online transformer monitoring is reasonable and is approved.

7.9.2.8. Substation Protection and Control Replacements

This program replaces control equipment approaching the end of its service life. SCE presents this in three sub-categories: distribution protection and control system replacement updates dated equipment, digital fault recorder replacement updates fault recorders to current WECC requirements, and 500 kV and 220 kV relay replacements which are FERC-jurisdictional. SCE's forecast is based on its plan for replacing equipment.[397] ORA proposes to accept SCE's three-year forecast and reduce 2014-2015 on the basis of overspending in 2013.[398] In rebuttal, SCE repeats its arguments about precedent and claims that ORA's proposal is not factually supported.[399] In this case, we find that SCE has not met its burden of proof. For the long lasting equipment contemplated here being replaced according to a multi-year plan, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the following years. We find ORA's 2014-2015 forecast reasonable and adopt it.

7.9.2.9. Substation Tools and Work Equipment

Portable tools and equipment in this category cost more than $1,000 such as generators and power tools that have relatively long lives. SCE uses 2012 recorded as the basis of its forecast noting that capital work has increased relative to the past and that it expects the level of work to remain high, necessitating more tools.[400] ORA proposes to accept SCE's three-year forecast and reduce 2014-2015 on the basis of overspending in 2013. ORA notes that as of May 2014,

[397] SCE-3V8 at 50-52.
[398] ORA-12 at 36-37 and ORA-12A.
[399] SCE-19V8 at 32.
[400] SCE-3V8 at 54-55.

SCE's annualized spending was below ORA's forecast.[401] In rebuttal, SCE repeats its arguments about precedent and claims that ORA's proposal is not factually supported and does not consider safety.[402] In this case, we find that SCE has not met its burden of proof. For the long lasting equipment contemplated here, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the immediately following years. Preliminary 2014 recorded information cited by ORA is consistent with that expectation. We find ORA's 2014-2015 forecast reasonable and adopt it.

7.9.2.10. Transmission and Substation Spare Parts

SCE's forecasts for transmission and substation spare parts are uncontested; we find these forecasts reasonable and adopt them.

7.10. T&D – Safety, Training, and Environmental Programs

This chapter addresses costs for safety, training, environmental programs, and employee-related costs such as informational meetings and employee recognition. All costs in this area are O&M. SCE's forecast is approximately $68 million (2012$) compared to: 2012 authorized of $80 million, 2012 recorded of $58 million, and ORA's forecast of $58 million. SCE cites lower hiring due to the timing of the 2012 GRC decision as the primary reason for the difference between 2012 authorized and recorded; ORA notes that SCE was not able to quantify or document that effect. SCE's safety statistics show improvement from 2008 to 2012, and SCE states that it believes continued progress can be made by continuing to provide safety training programs.[403] Our adopted forecast for this area is summarized below.

[401] ORA-12 at 38-39.
[402] SCE-19V8 at 35-36.
[403] SCE-03V9 at 1-10; ORA 9 at 35.

Account	Description	SCE	Adopted
566.250	Employee Recognition for Transmission Personnel	$0.065	$0.065
	Safety Programs for Transmission Personnel	$3.338	$3.338
	Informational Meetings for Transmission Personnel	$0.606	$0.606
	Transmission Environmental Services	$5.174	$5.174
	Training Delivery for Transmission Personnel	$4.388	$4.388
	Training Seat-Time for Transmission Personnel	$6.775	$6.098
	Training Delivery Benefits	$ (0.238)	$ (0.238)
	Total 566.250	$20.108	$19.431
573.250	Transmission Toxic Waste Disposal	$0.392	$0.392
582.250	Distribution Environmental Services	$2.289	$2.289
588.250	Employee Recognition for Distribution Personnel	$0.489	$0.489
	Safety Programs for Distribution Personnel	$11.533	$11.533
	Informational Meeting for Distribution Personnel	$3.633	$3.633
	Training Delivery for Distribution Personnel	$10.758	$10.758
	Training Delivery Benefits	$ (0.643)	$ (0.643)
	Training Seat-Time for Distribution Personnel	$14.345	$12.911
	Total 588.250	$40.115	$ 38.681
598.250	Distribution Toxic Waste Disposal	$5.120	$5.120
Total		$68.024	$65.912

7.10.1. T&D Training Seat-Time (Portions of Accounts 566.250 - Transmission and 588.250 - Distribution)

These are the labor and non-labor costs for employees to attend SCE-sponsored trainings. Non-labor costs include travel to attend trainings. SCE's total forecast is $21.120 million, which is $6 million higher than 2012 recorded and $5 million lower than the five-year average. SCE claims that

reduced hiring and delayed capital projects reduced the need for training in 2012. SCE states that it intends to hire additional front-line employees to execute the forecast increases in T&D capital and O&M activities, leading to increased training needs. SCE's forecast is based on specific planned training programs for different job categories and the number of employees expected to attend. Labor costs are forecast as: number of employees in the training * average wage * number of hours of training. SCE used a 5YA labor to non-labor ratio to forecast non-labor expenses.[404]

For the transmission account, ORA recommends using 2012 recorded for its total forecasts. ORA notes that costs declined considerably during 2008-2011, and that timing of the 2012 GRC decision would not explain low 2011 spending. ORA reviews historical data and concludes that "SCE has spent well below authorized in this area for a number of years . . . ." Similarly, ORA recommends 2012 recorded for the distribution account.[405] In rebuttal, SCE emphasizes that its forecast is based on program-by-program analysis and claims that ORA's forecast is insufficient. SCE notes that ORA's statements about embedded funding are illogical because costs for trainings that did not occur in 2012 are not in 2012 recorded. Finally, SCE notes that its total forecast is lower than any of 2008-2011 recorded.[406] As in D.12-11-051, we find that SCE's approach to developing its forecast by considering specific training needs and number of relevant employees is preferable to relying only on 2012 recorded. In particular, we note that SCE's forecast is considerably lower than the five-year average of recorded costs, casting doubt on ORA's analysis. However, as in D.12-11-051, we find that training costs are directly related to the number of employees, particularly new

[404] SCE-3V10 at 17-19.
[405] ORA-9 at 40-44 and 50-51.
[406] SCE-19V9 at 5-7.

employees. Since our total adopted labor forecast is lower than SCE's it is reasonable to adopt a 10% lower training forecast. Our adopted forecast is summarized below (millions of 2012$).

	SCE	Adopted
Training Seat-Time for Transmission Personnel	$6.775	$6.098
Training Seat-Time for Distribution Personnel	$14.345	$12.911
Total	$ 21.120	$19.008

7.10.2. T&D Training Delivery Benefits (Portions of Accounts 566.250 - Transmission and 588.250 - Distribution)

SCE forecasts certain benefits (cost reductions) related to consolidation of training in Operational Excellence.[407] As discussed in Section 25 below, we adopt SCE's estimates.

7.10.3. Employee Recognition (Portions of Accounts 566.250 and 588.250)

Employee recognition includes awards for safe practices and exemplary job performance. SCE claims that this program has been scaled down to focus on safety in recent years and that this type of program is encouraged in the industry. SCE anticipates future benefits such as fewer injuries and associated costs. SCE's forecast is based on 2012 recorded.[408] ORA recommends disallowing these expenses entirely on the basis that they are discretionary, not necessary to operate the business.[409] As noted in Section 10.4 below, SCE contends that these programs benefit ratepayers. In the case of T&D, we agree with SCE that these modest programs promote safety and are reasonable costs. We adopt SCE's forecasts.

[407] SCE-3V9 at 16-17.
[408] SCE-3V9 at 25-26.
[409] ORA-9 at 47.

7.10.4. T&D Environmental Services (Portion of Account 566.250 - Transmission and Entirety of Account 582.250 - Distribution)

Forecasts for environmental services include expenses for a variety of services (e.g., water quality) provided by the Corporate Environmental Health and Safety organization incurred on behalf of T&D projects and recorded in these T&D FERC Accounts. These are discussed in Section 11.2.2 below, where we adopt SCE's forecasts.

7.10.5. Uncontested Issues

There are many uncontested issues in this area, including: three entire Accounts (573.250, 582.250, and 598.250) and portions of Accounts 566.250 and 588.250. We have reviewed SCE's forecasts for these issues, and find them reasonable. SCE's uncontested forecasts are approved.

7.11. T&D – Other Costs and Other Operating Revenue (OOR)

This chapter addresses O&M expenses for contract management, write-offs, services, credits and related expense in addition to OOR not related to the sale of electricity. SCE's 2012 recorded expenses were $84.5 million (2012$) compared to $103.3 million authorized; SCE attributes the difference primarily to the timing of the 2012 GRC decision.[410]

There are several uncontested accounts in this area. We find reasonable and adopt SCE's forecasts for these uncontested items.

Our total forecast for operational support and other costs is shown below (millions of 2012$).

Account	Description	SCE	Adopted
566.280	Grid Contract Management	$ 2.485	$ 2.226
588.280	Distribution Construction Contract	$ 0.846	$ 0.846

[410] SCE-3V10 at 1-2.

	Management		
560.281	Transmission/Substation Capital-Related Expense	$ 8.778	$ 7.900
	Transmission/Substation Work Order Write-Off	$ 1.636	$ 1.636
	Total 560.281	$ 10.414	$ 9.536
583.281	Claim Write-Offs	$ 7.963	$ 7.963
586.281	Meter Credits	$ (4.608)	$ (2.625)
588.281	Distribution Work Order Write-Off	$ 10.139	$ 9.793
	Underground Locating Service	$ 10.471	$ 10.148
	Total 588.281	$ 20.610	$ 19.941
594.281	Distribution Capital-Related Expense	$ 17.159	$ 15.443
566.282	Transmission Facilities Maintenance	$ 4.560	$ 4.560
580.282	Distribution Facilities Maintenance	$ 10.698	$ 10.698
568.281	Transmission Operational Excellence Savings	$ (0.915)	$ (0.915)
590.281	Distribution Operational Excellence Savings	$ (3.168)	$ (3.168)
Total		$ 66.044	$ 64.505

Our adopted forecast for OOR is summarized below (millions of 2012$).

Account(s)	Description	Adopted
451.500	Ownership Charges	$ 1.697
454.500	Pole Rentals	$ 4.443
456.300, 456.306, 456.307, 456.308	Transmission and Distribution Services	$ 44.051
456.319, 456.320	Generation Radial Tie-Lines	$ 3.290
456.323	Tie-Line Facilities Rental Agreement	$ 0.307
456.900	Miscellaneous Revenue	$ 3.011
454.300	SCE-Financed Added Facilities	$ 35.139
454.350	SCE-Financed Interconnection Facilities	$ 14.934
456.700	Customer-Financed Added/Interconnection Facilities	$ 21.497
Total		$128.369

7.11.1. Grid Contract Management (Account 566.280)

Grid Contract Management group manages interconnection contracts, both FERC- and CPUC-jurisdictional. After contracts are executed this group manages them from beginning to end, including: security postings, meter data, production forecasts, billing, and contract modification or termination. SCE states that despite an increase in workload, labor costs have remained flat during 2008-2012. SCE includes six additional full-time equivalent employees in its labor forecast, citing its expectations that the number of contracts managed will double by the end of 2017. SCE cites several productivity improvements including templates, improved billing through software, and streamlined tax and reporting efforts. SCE's forecast includes a 4.5% annual productivity improvement. Non-labor costs have been flat from 2009-2012, after a new contract was implemented. SCE's non-labor forecast includes an increase at the same ratio as the labor forecast.[411]

ORA contends that SCE's requested increase is not justified, noting that expenses have fluctuated over the five recorded years. ORA claims that while SCE has received funding for additional staff in its last two GRCs, staff in this group has not actually increased. ORA recommends a forecast based on 2012 recorded.[412]

In rebuttal, SCE contends that ORA's recommendation ignores the consistent increase in number of contracts. SCE provides data and analysis suggesting that it is on track to meet its 2012 authorized staffing levels by late in 2014 and that number of contracts is increasing.[413]

[411] SCE-3V10 at 2-5.
[412] ORA-9 at 55-58.
[413] SCE-19V10 at 4-5.

SCE's data shows an approximately 30% increase in contracts from 2012 to end of August 2014. We agree with SCE that productivity improvements alone may not be adequate to address the forecast growth in number of contracts. However, ORA's point that recorded data does not support SCE's proposed increase is well-taken; SCE is likely able to make further productivity improvements in Grid Contract Management. Accordingly, we reduce the increment over 2012 recorded to $0.300 million, approximately enough for three additional employees. Our adopted forecast is shown below (millions of 2012$).

	SCE	Adopted
Labor	$ 2.217	$ 1.981
Non-Labor	$ 0.268	$ 0.245
Total	$ 2.485	$ 2.226

7.11.2. Meter Credits (Account 586.281)

Neither TURN nor ORA disputes SCE's forecast of meter credits. However, this forecast depends directly on the number of new meters adopted in Section 8.2.1 below. Applying this forecast ($16.269 million in 2015), using the approach suggested by SCE,[414] yields a credit of $2.625 million, which we adopt here.

7.11.3. Distribution Work Order Write-Offs and Underground Utility Locating Service (Account 588.281)

For distribution work order write-offs, SCE forecasts $10.139 million (2012$) based on a five-year average, excluding the Catalina undersea cable and 50% of a satellite system based on guidance in D.12-11-051.[415] ORA proposes a three-year average forecast of $8.759 million, citing a lack of detail in SCE's documentation.[416] TURN proposes removing two write-offs from SCE's

[414] SCE-19V10 at 8-9.
[415] SCE-3V10 at 11-13.
[416] ORA-9 at 59-60.

calculation. For one write-off, TURN claims that the entire amount has been recovered; for the other, TURN contends the original provision was made in error and that ratepayers lost the time value of money due to the escalation calculation. Adjusting for these, TURN recommends a forecast of $9.793 million.[417] SCE contends that ORA's recommendations should be rejected because SCE's forecast follows our guidance. SCE argues that TURN's proposal to exclude the first past write-off requires a "complicated and burdensome exercise" and that reversals in write-offs in one period naturally offset write-offs at that time. For the second proposed change, SCE explains that the original provision was not made in error and provides an illustration and recommends against an escalation rate adjustment provision.[418] In hearings, SCE admitted that the first write-off was caused by an organizational change, represented a rare circumstance, had been at least partly billed, but the amount collected was unknown.[419] We find that SCE has not adequately demonstrated that ratepayers have not lost the time value of money from the second adjustment as the impact of escalation is not shown in SCE's illustration or TURN-50. Further, we do not agree with SCE that TURN's proposal requires a complex analysis, and we do not require any general new reporting for write-offs. TURN's proposal is a reasonable adjustment to the recorded write-offs and is adopted.

For underground locating services, SCE forecasts $10.471 million based on a four-year (2009-2012) average. SCE excludes 2008 because of a significant rate change from one of its suppliers in 2009.[420] ORA proposes forecasting based on the 2012 recorded amount: $9.850 million. ORA notes that 2012 is comparable to

[417] TURN-5 at 35-36.
[418] SCE-19V10 at 11-13.
[419] 10 RT 939-943.
[420] SCE-3V10 at 16-18.

2008, excluded by SCE.[421] TURN recommends a four-year average, between 2010-2013, or $9.916 million. TURN contends there is a clear downward trend in expenses, which could justify using the LRY value.[422] SCE argues that ORA's recommendation is inconsistent with guidance from D.04-07-022 to use averages for accounts influenced by external forces. SCE notes that volume is much higher in 2012 than 2008. SCE calculates a 5YA (2009-2013) of $10.148 million, claiming that TURN inappropriately excludes 2009.[423] We agree that a 5YA is reasonable given the uncertainty in both price and volume moving forward. Accordingly, we adopt $10.148 million (2012$) for this service.

Our total forecast for Account 588.281 is summarized below (millions of 2012$).

	SCE	Adopted
Distribution Work Order Write-Off	$ 10.139	$ 9.793
Underground Locating Service	$ 10.471	$ 10.148
Total	$ 20.610	$ 19.941

7.11.4. Capital-Related Expense (Accounts 594.281 – Distribution and 560.281 – Transmission/Substation)

This category includes costs incurred during capital projects that do not qualify for capitalization, such as replacing insulators while replacing poles (a separate unit of property). SCE's recorded data indicates significant variation in the relation between capital expenditures and related expense. SCE bases its forecast on five-year averages of the ratio between capital expenditures and expense, multiplied by forecast expenditures in each of 2015 to 2017, and normalizing for 2015.[424] ORA proposes a 5YA of recorded expenses for Account

[421] ORA-9 at 60.
[422] TURN-5 at 37-38.
[423] SCE-19V10 at 15-16.
[424] SCE-3V10 at 26-30.

594.281, but accepts SCE's forecast for 560.281. ORA cites its belief in embedded funding and notes that SCE's capital expenditure forecast may not be entirely adopted.[425] SCE discusses certain inconsistencies in ORA's testimony, including that ORA only makes its proposal for the FERC account for which it leads to a reduction. SCE concludes that we should adjust these forecasts only based on adjustments to the capital forecast, excluding pole loading.[426] We agree with SCE that this forecast should be based on the historical relationship and the adopted capital forecast. Accordingly, we adjust SCE's forecasts for each account by 10% to approximate our reductions to non-pole loading capital expenditures, as shown below (millions of 2012$).

Account	Description	SCE	Adopted
560.281	Transmission/Substation Capital-Related Expense 0020	$ 8.778	$ 7.900
594.281	Distribution Capital-Related Expense	$ 17.159	$ 15.443

7.11.5. Facility O&M (Accounts 566.282 – Transmission/Substation and 580.282 – Distribution)

These costs are for certain facilities occupied by T&D personnel, such as cleaning, landscaping, and maintenance. SCE contends that costs were flat during 2008-2010 and that decreases in 2011-2012 were due to short-term cost savings (e.g., due to reduced frequency of certain cleanings) and SCE's concern with the timing of the 2012 GRC decision. SCE uses 2011 as the basis of its forecast, which SCE claims includes the results of aggressive cost-cutting relative to earlier years.[427] TURN recommends averaging 2011-2012, contending that some of the changes made during 2012 should be continued.[428] In rebuttal, SCE

[425] ORA-9 at 60-62.
[426] SCE-19V10 at 17-18.
[427] SCE-19V10 at 18-23.
[428] TURN-5 at 38-39.

accepts a small change proposed by TURN related to spill prevention, but rejects TURN's proposal to average 2011-2012. SCE contends that 2011 already includes aggressive savings and that 2012 maintenance practices are unsustainable.[429] We encourage SCE to continue to pursue cost-effective cleaning and maintenance strategies, while protecting employees and assets. We find SCE's forecast based on 2011 reasonable, and agree that 2012 may represent unsustainably low levels of maintenance.

7.11.6. SCE-Financed Added and Interconnection Facilities (Accounts 454.300 and 454.350)

Added facilities are facilities owned by SCE in addition to those required for base service. Interconnection facilities connect a customer's generator to SCE's system. SCE may choose to finance these facilities. SCE charges the relevant customers a monthly charge designed to ensure that general customers do not pay costs associated with these assets, and the revenues are recorded to OOR. SCE created its forecasts based on forecast net investment, multiplied by applicable rates, and normalized 2015 through 2017.[430] ORA recommends a five-year average, claiming that SCE's method is less reliable.[431] TURN accepts SCE's method, but proposes a different "erosion" rate (i.e., the amount of contracts terminating) based on 2007-2012 rather than 2003-2012, as proposed by SCE. TURN claims the first four years had a much higher erosion rate and that the later years are "more reflective" of the forecast period.[432] In rebuttal, SCE accepts ORA's forecast based on identifying some new, additional projects. SCE

[429] SCE-19V10 at 19-20.
[430] SCE-3V10 at 47-49.
[431] ORA-9 at 69-72.
[432] TURN-5 at 40-41.

claims this forecast is higher than that proposed by TURN.[433] We adopt ORA's forecasts, which are uncontested.[434]

7.11.7. Customer-Financed Added/Interconnection Facilities (Account 456.700)

This account records costs similar to those above, but for facilities financed by customers. SCE and TURN use the same forecast methods as discussed above. SCE updates its forecast to use a 5YA erosion rate, very similar to TURN's forecast. We accept SCE's updated forecast.

8. Customer Service

8.1. Customer Service – O&M

Our adopted O&M forecast for contested issues is summarized below (millions of 2012$). For uncontested issues, we adopt SCE's forecast.

Account	Activity	SCE	Adopted
902	Meter Reading	$17.329	$16.771
903.500	Billing Services	$22.225	$21.458
903.800	Customer Contact Center	$47.435	$47.435
904	Uncollectible Expense	0.238%	0.238%
907.700	Program Management Organization	$7.415	$6.343
586.400	Test, Inspect and Repair	$16.505	$16.505
587	Customer Installation and Energy Theft	$7.946	$7.946
908.600	Business Customer Division	$18.879	$18.879
Total, excluding Uncollectibles		$137.734	$135.337

8.1.1. Meter Reading Operations (Account 902)

This account captures all expenses related to the reading of customer meters. A significant change since the 2012 SCE GRC is that at the end of 2012, 98% of SCE's meters were being read automatically by the Edison

[433] SCE-19V10 at 23-25.
[434] TURN OB at 126.

SmartConnect® (ESC) system. By the end of 2015 the level of automated meter reading/data collecting is expected to increase to 99%. However, for the 1% of customers that opt-out of the ESC system, which SCE states is about 52,500 meters, these will still need to be manually serviced. SCE forecasts total costs of meter reading in 2015 to be $0.31 per read, compared to $0.86 in 2008.

SCE originally sought $19.255 million ($13.821 million Labor and $5.434 million Non-labor) for TY2015, an increase of $6.035 million (46%) over 2012 recorded adjusted expenses of $13.220 million with adjustments for ESC incremental costs and benefits. Future year adjustments include ongoing incremental ESC costs of $5.740 million, customer growth of $273,000, a program change adjustment of $1.146 million for ESC opt-out meter reading costs, and Operational Excellence savings of $1.123 million to be achieved by lowering staffing levels.[435]

ORA recommends the Commission adopt a forecast of $14.544 million ($10.720 million Labor and $3.823 million Non-labor) which is 25% less than SCE's forecast.[436]

TURN recommends the Commission authorize $12.984 million which is 36% less than SCE's forecast.[437]

ORA's main argument to adopt a forecast 25% less than SCE's forecast is that it is consistent with SCE's 2013 recorded expenses because 2013 should be representative of ESC steady-state operations.[438] TURN proposes a related reduction in automatic meter reading costs of $1.4 million based on 2013 recorded, arguing that year is more representative than 2012, used by SCE.

[435] SCE-04V2 at 13-22.
[436] ORA-13 at 12, Lines 4-18
[437] TURN-08A at 33.
[438] ORA-13 at 12, Lines 6-9

SCE responds that it was only by the end of 2012 that 98% of SCE's meters were being read automatically by the ESC system. The ESC system/program is still in the infant stages and will take time to mature and reach a steady-state of operations. As such, ESC SOC cost is still in a dynamic state as are the Opt-Out Program costs. SCE notes that SOC hiring was not completed during 2012 and that SOC has been adding services in 2013 and 2014. Some of these services also entail further expenses such as leased air time. SCE argues that TURN misunderstands the 2013 data.[439]

SCE has shown that there are important changes occurring at SOC that are not captured by historical data. We find that SCE's forecast of automatic meter reads via the ESC system and SOC costs is most reasonable.

In update testimony, SCE lowered its labor forecast related to manual meter reading by $1.926 million.[440] In light of this adjustment, portions of ORA's and TURN's comments on manual meter reading are moot. TURN's proposed reduction of $0.558 million for manual readings of Non-Opt Out meters is reasonable.

Therefore we find it reasonable to adopt a forecast for O&M in this account of $16.771 million (2012$) based on SCE's updated forecast and TURN's adjustment.

8.1.2. Billing Services (Account 903.500)

Expenses recorded to this account are for routine billing, special billing, rebilling and customer account analysis.

For 2015, SCE originally forecast $22.277 million ($19.773 million Labor and $1.893 million Non-Labor),[441] a 2.5% increase for this subaccount. The forecast is

[439] SCE-20 at 3-8.
[440] SCE-74 at 3.
[441] SCE-04V2 at 85.

based on 2012 adjusted and recorded data and includes upward adjustments of (1) $2.057 million adjustment for incremental Meter Data Management System steady-state billing exception related costs; (2) a $435,000 adjustment to reflect customer growth; and (3) $1.069 million adjustment for program changes including program enrollments, support for the enlarged font and Braille bill format, and funding for a base level of credits for two of SCE's Service Guarantees.[442] SCE reduced its labor forecast by $0.052 million after hearings and briefs.[443]

ORA recommends the following be denied: SCE's Service Guarantee Program funding request of $173,000; SCE's request for incremental funding of $250,000 for the Medical Baseline program; SCE's request for incremental funding of $515,000 for the Home Area Network (HAN); and SCE's request for $79,000 incremental funding to support customer enrollments in customer Lifestyle Packages.[444]

ORA cites the last three GRC's[445] in which we agreed that shareholders should continue to fund payments of inconvenienced customers. This is clearly stated in SCE's TY 2006 GRC Decision:

> Regarding the payments to customers, these are payments that result from the company not meeting its commitments to individual customers. If the company is unable to meet its commitments, the shareholders and not the ratepayers should be responsible for reimbursing the inconvenienced customer.[446]

Therefore, we deny SCE's request of $173,000 for the Service Guarantee Program.

[442] SCE OB at 172-173.
[443] SCE-74 at 3.
[444] ORA-13 at 31-34.
[445] D.06-05-016 at 122; D.09-03-025 at 108; D.12-11-051 at 228.
[446] *Ibid.*

SCE's Medical Baseline Program forecast was based on historic growth and the historic ratio of enrolment volume to total program participation and ORA did not dispute the 9% historic growth rate in total medical baseline participation.[447]

Therefore, we find SCE's request for incremental funding of $250,000 for the Medical Baseline program reasonable.

ORA contends that the forecast in the increase of HAN enrollments in 2015TY over 2012 recorded expenses is not significant enough to increase funding for the HAN, and SCE discontinued the Lifestyle Package.[448]

Therefore, we do not adopt SCE's recommendation for incremental funding of $515,000 and $79,000 for HAN and customer enrollments in customer Lifestyle Packages respectively.

SBUA recommends the Commission reduce SCE's Customer Service forecast for capital requirements by at least 20%.[449] SBUA challenged SCE's self-reported Service Guarantee results and is concerned SCE is moving too fast with Customer Service software projects which will not be beneficial to small businesses.[450] SBUA did not provide any evidence to substantiate questioning the validity of SCE's results and only speculate that Customer service software projects will not be beneficial to small businesses.

Therefore we do not accept SBUA's recommendations.

8.1.3. Customer Contact Center (Account 903.800)

Costs recorded in this subaccount relate to customer contact centers providing 24-hour access to an SCE representative. In this rate cycle, SCE assumes more calls and more complex problems that take longer to resolve.

[447] ORA-13 at 33-34.
[448] ORA-13 at 34.
[449] SBUA-01 at 6.
[450] *Ibid*. at 20.

SCE's revised forecast of $47.435 million is an increase over 2012. The forecast is based on 2012 recorded costs plus adjustments for (1) incremental ESC-related costs of $3.533 million; (2) customer growth of $956,000; (3) program changes of $2.625 million for emerging customer contact channels and increased compensation for Customer Service Representatives (CSRs); and (4) a cost reduction of $4.731 million for Operational Excellence initiatives.[451]

ORA recommends a lower increase in ESC related costs, based on fewer employees and no increase in phone bills. ORA rejects the customer growth adjustment. ORA rejects SCE's proposed increase in ratio of supervisors to CSRs and SCE's proposed $2.00 per hour wage increase for CSRs, claiming the Total Compensation Study (TCS) discussed below in Section 9 shows that CSR compensation is above market.[452]

TURN recommends no rate adjustment for CSR wage increases, claiming that this increase is implicitly captured by the escalation rates adopted in Section 18 below.[453]

SCE contends that ORA's recommendations do not consider the factors driving increased Average Handle Time and thus Customer Contact Centercosts, such as new ESC data enabling CSRs to provide more services to customers as "Energy Advisors." SCE explains that phone bills are not included in CSRs' non-labor expenses. Further, SCE explains that although customer-call volume has declined, total customer-contact volume has increased. Finally, SCE argues that increased supervision and salaries are necessary to support CSRs handling increasingly complex calls. These increases are not covered in the attrition year mechanism, which is targeted at inflation.[454]

[451] SCE OB at 175 and SCE-74 at B-1.
[452] ORA-13 at 41-45.
[453] TURN-8 at 42.
[454] SCE-20 at 34-45.

We agree with SCE that call center employees face increasingly complex tasks, warranting both increased supervision and increased wages, and further that these specific wage increases are tied to a change in job skills required, not general inflation. Therefore, we adopt SCE's forecast.

8.1.4. Uncollectible Expense (Account 904)

Costs recorded in this subaccount relate to expenses for all revenue components of uncollectible customer accounts. Historically, recorded expenses are authorized based on an estimate of uncollectible expense factor expressed as a percent of gross SCE revenue. This "uncollectible factor" is applied to various components of SCE's revenue as each is reviewed in proceedings other than the GRC.

For TY2015, SCE forecasts an uncollectible factor of 0.238%, based on a 5YA before removal of the impact of the residential disconnection Order Instituting Rulemaking (OIR Impact). This proposal is above the current factor of 0.205%[455] and above the 2012 recorded factor excluding OIR Impact of 0.222%. In the 2012 GRC we found that a 10-year average of recorded uncollectible factors was reasonable.[456] The 10-year average stated by SCE is 0.201%.[457]

However, ORA recommends that SCE's uncollectible factor be based upon the 2012 LRY factor of 0.222% with no adjustments for the impact that the change in OOR and OIR deposit policy change will have on future uncollectible expense.[458] TURN simply recommends reducing SCE's uncollectible expense by $1.3 million, the uncollectible portion of customer bills that it believes will be paid by the California Climate Credit and other greenhouse gas revenues.[459]

[455] D.12-11-051 at 337.
[456] D.12-11-051 at 337.
[457] SCE-04V2, Figure IV-22 at 132.
[458] ORA-13 at 50.
[459] TURN-05 at 117.

We agree with SCE and the prior GRC decision that a historical average is appropriate to avoid undue influence of variable economic factors. SCE's forecast is reasonable. We agree with SCE that TURN's suggestion of incorporating the California Climate Credit and other GHG revenues would be double counting.

8.1.5. Program Management Organization (PMO) (Account 907.700)

Costs recorded in this subaccount relate to costs for SCE's PMO. The PMO develops and maintains the Customer Service long-term capital systems and business capabilities plan, the portfolio planning, and governance process and assesses the sustainability of critical systems.

For TY2015 SCE forecasts $7.415 million ($3.936 million Labor and $3.479 million Non-Labor) a $1.437 million increase (19%) over 2012. The forecast is based on 2012 recorded expenses with upward adjustments of (1) $630,000 for the development of optimized data management and complex business analytics; (2) $267,000 to reflect the total annual costs associated with the three employees it hired in 2012; and (3) $541,000 to support 2014 to 2017 forecasts of capital software projects.[460]

The expenses recorded in this account demonstrate year-to-year historical cost fluctuations.[461] The dispute here is whether or not SCE provided adequate details as to what additional expenses will be incurred in TY2015. ORA and TURN both recommended using multi-year averages, 4 and 6 years respectively. ORA's forecast removed outlier expenses within the 2008-2012 data and recommends a forecast of $6.343 million which is $1.072 million (15%) less than SCE's request. TURN uses a 2008-2013 average, noting that SCE forecast a $1.06

[460] SCE OB at 179.
[461] SCE-04V2, Figure VI-28 at 166.

million increase in 2013, but only recorded a $0.072 million increase.[462] SCE acknowledges this fluctuation as a result of project lifecycles and contends that TURN and ORA ignore known information about additional costs (e.g. data management, portfolio oversight staffing).[463]

Because of the historical fluctuations resulting from the length of project lifecycles and the lack of information of the current project lifecycles in SCE's forecast, we adopt ORA's proposed $6.343 million (15% less than SCE's request) for TY2015. We agree with TURN that the fact that SCE's 2013 recorded results are well below SCE's forecast, despite including a significant portion of the increase calls the validity of SCE's forecast increases into question. This forecast is a significant increase over 2012 recorded, and allows SCE some funding to implement the additional functions it proposes.

8.1.6. Test, Inspect and Repair (Account 586.400)

Costs recorded in this subaccount relate to SCE's Electrical Metering Services, Engineering and Meter Shop operations, and the field maintenance and repair of electric billing and load survey meters.

For TY2015 SCE forecasts costs of $16.505 million an increase of approximately 24% over 2012 recorded expenses. The forecast is based on 2012 recorded expenses with upward adjustments for (1) ESC incremental costs of $2.831 million; (2) customer growth related expenses of $278,000; (3) program changes of $1.263 million for acceptance testing of 50 percent of all SmartConnect meters that are returned from the manufacturer under warranty; and (4) Operational Excellence savings of $1.183 million for consolidation of management and supervisory positions, as well as technical specialists,

[462] TURN-8A at 45-46.
[463] SCE-20 at 46.

engineering, administrative, and analytical support personnel throughout all functional areas in the 26 field locations.[464]

For TY2015, ORA recommends $13.210 million which is $3.464 million (21%) less than SCE's request for TY2015. Specifically, ORA recommends no additional funding for ESC incremental costs of $2.831 million and no additional funding of $1.262 million reflecting added O&M costs of performing warranty meter acceptance testing.[465]

SCE rejects ORA's arguments for a variety of reasons including that O&M in this account is related to the total population of meters instead of new meters and that there are new functions and new employees required in the ESC.[466]

We find that SCE's revised forecast of $16.505 million is reasonable. SCE demonstrated that ORA did not recognize that 2013 was not a reflective of the Test Year, and the implementation of ESC is still in a state of ongoing change and has not reached a steady-state in which there is a stable state of expenses.

8.1.7. Customer Installation and Energy Theft Expense (Account 587)

SCE's TY2015 forecast of $7.946 million ($6.947 million Labor and $0.999 million Non-Labor) is a 14% increase above 2012 recorded expenses. Adjustments include (1) ESC incremental costs of $1.180 million for two new energy theft programs and (2) customer growth related expenses of $144,000.

SCE's reasoning for the increase is that the impact ESC has had on Customer Installation and Energy Theft operating costs incurred prior to 2012 are not representative of future expectations and thus are not suitable to support the use of historical averages or trends to forecast future costs.[467]

[464] SCE-04V2 at 23-32 and SCE-74 at B-1.
[465] ORA-13 at 19-23.
[466] SCE-20 at 52-57.
[467] SCE-04V2 at 49.

ORA contends that ESC deployment was completed in 2012, and that 2013 recorded expenses declined relative to 2012. Accordingly, ORA recommends using 2012 recorded.[468]

We agree with SCE that 2012 is not representative in this instance. With the implementation of ESC and the accuracy of the data being analyzed and the ability to detect patterns of theft which triggers follow-up and investigations that previously would not have happened, new expenses will arise. Again the theme of the impact of the newly implemented ESC is displayed, as this is a maturing program that has not yet reached a steady state. SCE's forecast for Account 587 of $7.946 million ($6.947 million Labor and $0.999 million Non-Labor) is reasonable.

8.1.8. Business Customer Division (Account 908.600)

SCE forecasts $18.879 million based on 2012 recorded and three adjustments, for a net reduction of $1.340 million.

SBUA made a number of specific recommendations on funding levels for specific issues of interest to small commercial customers. Chief among these recommendations is that the Commission should condition approval of SCE's Economic Development Services (EDS) funding on the promise that SCE will spend 30% of this funding to support retention of small businesses as defined under the California Department of General Services.[469] SCE responds that this recommendation is impractical because SCE does not track relevant data and that that SBUA ignores the existing EDS contributions to small business.[470]

We agree with SCE. SBUA's recommendations are general based on its witness's expert opinions but does not provide evidence that their

[468] ORA-13 at 26.
[469] SBUA-1 at 6.
[470] SCE-20 at 47-49.

recommendation benefits ratepayers. SCE's forecast for this account is otherwise uncontested, and we find it reasonable.

8.2. Customer Service – Capital

8.2.1. Meter Services Organization (MSO)

This section addresses capital requirements for the MSO. The largest component of the MSO general capital forecast is for meters. SCE's forecast is divided into four components: new growth meter installations, replacement meters, legacy meters, and Real Time Energy Meters (RTEM).[471]

SCE originally forecast $28.508 million in 2014 and $33.766 million in 2015 in MSO capital expenditures.

ORA recommend a total of $11.613 million in 2014, and $12.457 million in 2015 in MSO capital expenditures.

In the 2012 GRC SCE forecasted $73.288 million in meter capital expenditures for 2010-2012. The Commission adopted $51.3 million for meter capital expenditures for the same time frame. SCE's actual recorded meter capital expenditures form 2010-2012 was $31.709 million. SCE spent only 62% of the Commission authorized meter capital expenditures for 2010-2012.

In this GRC, the main driver creating the difference in SCE and ORA's forecast is the number of meters forecasted in each of their calculations. In Section 16 below, we adopt TURN's forecast of new meter connections. The parties agree that the new meter connections forecast should be the basis of the new growth meter installations.

SCE's revised meter unit cost forecast is uncontested.[472] We apply these unit costs to our adopted new meter connections to calculate a new meter installation expenditure forecast.

[471] SCE-04V2 at 60.
[472] SCE-20 at 62-63.

For residential replacement meters, ORA proposes a method based on the ratio of growth meters to replacement meters.[473] SCE shows there is no correlation between these quantities.[474] We find SCE's forecast reasonable.

For Commercial and Industrial (C&I), agricultural, and RTEM replacement meters, ORA proposes to use 2013 recorded meter volumes in place of SCE's five-year average.[475] SCE rejects ORA's approach as arbitrary, and claims that the averaging method is appropriate to smooth fluctuations in the pattern. SCE also notes that some meter replacements during 2010-2012 were charged to the ESC balancing account and that ESC deployment has delayed some RTEM replacements.[476] SCE's data shows a clear downward trend for these volumes, with overall changes from 2008 to 2013 from negative 77% to negative 83%. SCE has not adequately explained why it does not foresee this trend to continue in the future. Accordingly, we adopt ORA's proposed volumes.

For RTEM meter unit costs, ORA proposes using 2013 recorded value of $1,400.[477] SCE neither rebuts this value, nor explains its own proposed value in testimony.[478] ORA's value is reasonable and is adopted.

For legacy/opt-out meters, ORA accepts SCE's unit costs, but proposes lower volumes based on recorded monthly increases in opt-out customers.[479] SCE does not rebut this proposal, and in update testimony, SCE reduces its forecast, consistent with D.14-12-078. We adopt SCE's updated forecast.

SCE requests funding for 16,667 delayed ESC meter installations in 2015. SCE also plans to replace 1,010 outdated agricultural meters (called PCAN

[473] ORA-13 at 68.
[474] SCE-20 at 64-65.
[475] ORA-13 at 69-72.
[476] SCE-20 at 66-67.
[477] ORA-13 at 72.
[478] SCE-4V2 at 65, SCE-20.
[479] ORA-13 at 69-70.

meters) during 2014-2016, claiming they are obsolete and a safety hazard.[480] ORA recommends a slower replacement rate for the PCAN meters, noting that SCE had not begun this project or selected a contractor by May 2014. ORA proposes rejecting the delayed installations outright, noting that SCE recorded capital expenditures for this program in 2013, counter to its direct testimony.[481] SCE does not rebut either of these positions. We find ORA's forecast reasonable.

For other items, SCE's forecast is undisputed and is adopted. Our adopted forecast is summarized below (millions of nominal$).

Growth Meters		2014	2015
	Residential	$ 3.986	$ 6.370
	C&I	$ 3.452	$ 4.417
	Agricultural	$ 0.203	$ 0.209
Replacement Meters			
	Residential	$ 0.792	$ 0.724
	C&I	$ 1.438	$ 1.469
	Agricultural	$ 0.275	$ 0.281
	RTEM	$ 0.630	$ 0.643
Delayed ESC Installations		$ -	$ -
PCAN Meters		$ 2.024	$ 2.066
Opt-Out/Legacy Meter Replacements		$ -	$ -
Specialized Equipment		$ 0.314	$ 0.214
Structures and Improvements		$ 0.775	$ -
Total		$ 13.888	$ 16.392

8.2.2. Business Customer Division (BCD)

SCE forecast a total of $1.415 million in 2014 and $1.815 in 2015 in BCD capital expenditures including two categories: structures and improvements and specialized equipment. SCE states the structures and improvements funds will

[480] SCE-4V2 at 65-66.
[481] ORA-13 at 70-71.

be used to improve energy education centers. The specialized equipment is used to assist customers seeking to improve energy consumption management.[482]

For structures and improvements, ORA accepts SCE's forecast.[483] ORA recommends 2013 recorded for specialized equipment.[484]

SCE responds that ORA's forecast for specialized equipment ignores support SCE provided for its own forecast and inappropriately ignores inflation.[485] We agree. SCE's forecast is reasonable and is approved.

8.3. Customer Service – OOR

D.14-12-078 directs SCE to include certain information about its Opt-Out program in its "next available" GRC and adopted the following Opt-Out fees and charges for SCE:[486]

For Non-California Alternative Rates for Energy (CARE) Customers:

Initial Fee	$75.00
Monthly Charge	$10.00/month

For CARE Customers:

Initial Fee	$10.00
Monthly Charge	$5.00/month

These adopted fees are lower than those originally proposed by SCE in this proceeding, with the exception of the initial, non-CARE fee (SCE proposed $71).[487] In D.14-12-078, we also anticipated that the fees and charges would need to be adjusted over time, as additional cost and revenue information is collected.[488] SCE stated in update testimony that it would remove $7.2 million in

[482] SCE-4V3 at 49-51.
[483] ORA OB at 218.
[484] ORA-13 at 72-74.
[485] SCE-20 at 69-70.
[486] Ordering Paragraphs 8, 12.
[487] SCE-04V2 at 208-209.
[488] D.14-12-078 at 3-4.

opt-out fees from its OOR revenue to account for the new fees.[489] This change has the effect of eliminating opt-out fees from SCE's forecast entirely. This is necessary to avoid double counting of this revenue in the GRC and in the balancing account.[490]

We adopt SCE's final forecast, as summarized below (millions of nominal$).

OOR Revenue Forecast	SCE - original	Adopted
Opt-Out CARE-Initial	$0.051	$0.000
Opt-Out NON-CARE-Initial	$0.192	$0.000
Opt-Out CARE-Monthly	$1.433	$0.000
Opt-Out NON-CARE-Monthly	$5.564	$0.000
Subtotal, Opt-Out	$7.240	$0.000
Subtotal, Other Fees and Charges	$25.569	$25.569
Total	$32.809	$25.569

9. Information Technology and Business Integration

The Information Technology (IT) Operating Unit (OU) is responsible for the management of SCE's applications and technology infrastructure. Expenses for IT are separated into three categories: Operation & Maintenance (O&M), Capital, and Capitalized Software. O&M encompasses cybersecurity, managing software license and maintenance agreements, and supporting new capitalized software applications. Capital expenses, in addition to software, support hardware refresh and growth, disaster recovery, regulatory requirements, electric delivery support services, maintenance of fiber optic cable and microwave communication equipment, and cybersecurity.

[489] SCE-74 at 3.
[490] SCE Comments at 12.

9.1. IT – O&M

Our adopted O&M forecast is summarized in the following table (millions of nominal$):

Description	Account	Adopted
Infrastructure Technology Services	920/921	$106.680
Information Technology Services	931	$4.107
Technology Delivery & Maintenance	920/921	$48.943
Cybersecurity & Compliance	920/921	$17.384
Enterprise Information Management & Architecture	920/921	$16.946
Client Services & Planning	920/921	$17.666
Incremental O&M for New Software	920/921	$8.820
Total		$220.546

9.1.1. Infrastructure Technology Services (ITS) (Account 920/921)

The primary purpose of the Infrastructure Technology Services Division is to provide "reliable, responsive, and cost-effective operational IT products and services for more than approximately 20,000 SCE and contingent workers across SCE."[491] SCE's 2015 ITS forecast requested $38.762 million for labor expenses and $74.692 million for non-labor, totaling $113.454 million.[492] ORA recommended $45.005 million for labor and $57.26 million for non-labor, a $102.265 million total.[493] The difference between these two forecasts rests on disagreements over the methodology used to calculate the baseline, the addition of an itemized list to non-labor expenses, and how to account for workforce reductions.

SCE and ORA disagree over whether to use the LRY or Four-Year Averaging methodologies to calculate the forecast baseline for 2015. SCE

[491] SCE-05, Vol. 1 at 10.
[492] *Id*. at 22.
[493] ORA-15 at 5-6.

calculates its baseline forecast using LRY to build off the 2012 recorded amounts. It does so knowing that "[a]lthough historical recorded data indicates an averaging methodology would most closely follow the Commission's guidance, we have chosen the last recorded year as it best represents the basis for expenses we anticipate beginning in 2015" and "it yields a lower number than ORA's 4 year average."[494] ORA, on the other hand, argues for using a four-year average to calculate the baseline since "this is what Commission guidance would recommend, which SCE acknowledges."[495]

Past decisions have addressed the circumstances necessary for applying each methodology. In particular, both parties cite to the PG&E 1990 GRC to distinguish between averaging and LRY: LRY should be used when recorded figures have been stable or trending in a certain direction for three or more years whereas averaging is used for accounts with "significant fluctuations in recorded expenses from year to year."[496] Here, from 2009-2012, labor shows year-to-year changes of +10.8%, 0%, and -6.8% respectively while non-labor shows changes of +2.7%, +6.6%, and -10.5%; and the totals show changes of +6.2%, +3.6%, and -8.9% (SCE-05, Vol. 1, Figure II-5). Since these numbers are neither stable nor do they indicate a trend, the four-year averaging methodology proposed by ORA is the most appropriate for determining the baseline forecast.

SCE and ORA also disagree about whether SCE should be allowed to add itemized, non-labor expenses to its baseline forecast. According to D.89-12-057, itemized expenses may be added if they are "specific changes in the level of expenses in a particular account, which are known or reasonably expected to occur."[497] SCE asserts that its itemized expenses for non-labor will increase "due

[494] SCE-05 V1 at 22; SCE-21 at 3.
[495] ORA-15 at 6.
[496] D.89-12-057 at 15; *see also* ORA-1 at 6 and SCE-05, Vol. at 9.
[497] D.89-12-057 at 15.

to software license and maintenance expenses for capitalized software projects entering into the capitalized five-year maintenance and support period, as well as growth in the number of licenses and escalation of the cost of existing licenses."[498] ORA, however, "does not accept SCE's itemized list of additional expenses as these expenses for software license increases are not new. They are accounted for in historical costs and therefore no incremental increase is required."[499] Indeed, SCE responded to an ORA data request that the "drivers of costs" for 2012 recorded expenses of software licenses and maintenance expenses were 72% "new software licenses" and 19% due to escalation of the cost of existing licenses.[500]

SCE argues that it "typically capitalizes the license and maintenance fees for 5 years" while, after that period, "SCE continues to pay annual license and maintenance fees, which are a recurring O&M expense, until the software is replaced or retired."[501] SCE misunderstands ORA. In fact, ORA contends those O&M expenses for capitalized software projects entering into the expensed five-year maintenance and support period, growth in the number of licenses, cost increases of licenses, and new software licenses "are adequately captured in historical costs." Indeed, SCE stated that these particular items already drove the costs of the 2012 recorded expenses for software licensing and maintenance in response to ORA data requests.[502] Since many of these costs are captured in the historical costs, we see no reason to allow 100% of SCE's increase to non-labor spending; however, it also seems unlikely that the historical costs could cover 100% of the costs of SCE's itemized expenses. Accordingly, to account for new

[498] SCE-05, Vol. 1 at 23.
[499] ORA-15 at 6.
[500] *Id*. at 6-7.
[501] SCE-21 at 6.
[502] ORA-15 at 6-7.

licenses and some escalation in the cost of existing licenses, we will allow 30% – $4.170 million (SCE proposed non-labor increase of $13.901 million x 0.3) – of the itemized increase to be added to the non-labor baseline.

Finally, ORA and SCE differ on how to account for reductions in SCE's workforce. ORA argues that SCE's 11% forecast decrease in the number of desktop and laptop computers between 2012 and 2015 indicates an overall workforce reduction of approximately 10%, thereby requiring a 10% reduction to the ITS baseline forecast.[503] In fact, SCE made a direct link between the number of employees and ITS expenses during the 2012 GRC.[504] However, a 10% forecast reduction would be too high here since half (three of six) of the ITS groups do not carry out functions related to employee headcount.[505] If workforce reductions were not otherwise accounted for, a 5% decrease in the baseline forecast would be appropriate absent specific numbers quantifying the actual reduction. Nevertheless, since SCE's $11.117 million OpX adjustments already factor in workforce reductions,[506] utilizing both SCE's and ORA's reductions would be double-counting and, therefore, untenable. As such, because SCE's $9.826 million OpX reduction to labor costs and $1.291 million OpX reduction to non-labor costs considers not only labor cost reductions but efficiency reductions as well, it is most appropriate to reduce the baseline forecast by those amounts.

In sum, since the OpX reductions, partial increase of the itemized expenses, and ORA's four-year averaging methodology are appropriate, we adopt the 2015

[503] *Id*. at 7.
[504] *See* ORA-42 excerpting SCE TY 2012 Ex. SCE-05, Vol. 2.
[505] SCE-21 at 5.
[506] *Id*. at p. 4.

ITS forecast in the following amounts: $40,179,500 for Labor and $66,500,750 for Non-Labor (total: $106,680,250).[507]

9.1.2. Cybersecurity & Compliance (Account 920/921)

The Cybersecurity & Compliance Division (C&C) maintain "the confidentiality, availability, integrity, and accountability of information technology systems and operations through security engineering and risk management."[508] For C&C in 2015, SCE requests $7.529 million for labor and $11.494 million for non-labor (total of $19.023 million), whereas ORA recommends $6.801 million for labor and $8.078 million for non-labor ($14.879 million total). For purposes of comparison, in 2012 SCE recorded $5.254 million for labor and $1.224 million for non-labor (totaling $6.478 million) in the same category.[509]

Though ORA does not dispute the importance of cybersecurity and protection or the need to increase funding above 2012 levels, it nevertheless takes issue with SCE's 2015 C&C forecast. ORA asserts that SCE's forecast is too high in part because it "neglected to remove" C&C costs for its SONGS Nuclear Operating Unit.[510] SCE explains that "historical and forecast costs for all C&C employees" working in the Nuclear Operating Unit were embedded in the Technology Delivery and Maintenance (TDM) FERC Account 517 "to simplify and condense the [GRC] submission."[511] Those costs are listed in an SCE workpaper, TDM SONGS 517 Savings, in the line item for "Cybersecurity

[507] The baseline is the 2009-2012 Labor average of $50,005,500 and the 2009-2012 Non-Labor average of $63,621,750. $9.826 million and $1.291 million are then subtracted from the baseline, respectively, for the OpX reduction and $4.170 million is added to Non-Labor for itemized expenses.
[508] SCE-05, Vol. 1 at 46.
[509] SCE-05, Vol. 1 at 52.
[510] ORA-15 at 12.
[511] SCE-21 at 9.

reductions (cumulative)."[512] When the Commission ordered the removal of SONGS costs from the GRC Application, SCE complied by submitting SCE-14 on April 7, 2014 with FERC Account 517 removed, thereby eliminating the C&C costs related to SONGS. As such, ORA's assertion that SCE failed to remove these costs is incorrect and is not considered.

ORA also argues that SCE's rate of increase of contracted, i.e. non-labor, workers "is likely to be unattainable." For example, SCE only spent 60% of its non-labor budget in 2013. If it could not spend its entire allotment in 2013, there is no reason to believe SCE will be able to do so in the future.[513] SCE counters that while it only spent 60% of its non-labor budget, it filled seven of a forecast nine positions in 2013, 78% of its target.[514] Additionally, "[a]pproximately half of the requested non-labor increase is for contracts with external firms for penetration testing, vulnerability assessments, tools for real time controls and monitoring as well as software license and maintenance agreements. The remainder of the non-labor increase would be for 4 new contractors in the 2013-2014 time frame and 7 additional contractors in 2015. In 2014 alone SCE has added 22 new employees and brought in 2 new contractors in this area. Additionally we have brought in several fixed price contractors for the types of specialized services already mentioned. SCE believes our goals are reasonable and attainable."[515] Considering SCE hired 78% of its non-labor positions in 2013 and hired at least two more contractors in 2014 out of a forecast four, budgeting for seven additional contractors in 2015 does not seem "unattainable."

Nevertheless, a broader question remains as to whether SCE has presented sufficient evidence explaining the need for a substantial increase in non-labor

[512] Workpaper SCE-05, Vol. 1, Ch. I-II at 271-272; *see also* SCE-05, Vol. 1, fn. 46.
[513] ORA-15 at 12.
[514] SCE-21 at 8.
[515] *Id*.

spending for C&C. While labor spending gradually increased from $5.254 million in 2012 to $7.529 million (forecast) in 2015, an average yearly increase of 12.7%, non-labor spending grew dramatically from $1.224 million in 2012 to $11.494 million in 2015, an average yearly increase of 111% and an 839% increase overall. SCE has presented sufficient evidence to demonstrate the importance of addressing cybersecurity and compliance issues, but it has not explained the drastic increase in non-labor spending over such a short time frame. This sharp increase stands out even more when contrasted with the gradual rise in expenses for labor over the same period as well as the *decrease* in non-labor spending from $4.792 million in 2010 to $1.224 million in 2012. While we recognize that non-labor expenditures on contracts with external firms and contractors may be more costly than internal labor expenditures, justification for the current 111% rate of increase requires a more detailed explanation. Therefore, we cannot adopt SCE's entire non-labor forecast. Comparing 2014 and 2015, the labor forecast increased by nearly 11%. Since SCE has demonstrated the critical nature of cybersecurity and compliance and that costs are growing, in this instance, we find that an increase of 22% (double the labor rate) over the 2014 non-labor forecast to $9.855 million, is appropriate. Furthermore, because SCE's increase in the labor forecast from 2014 to 2015 is in line with year-to-year increases starting in 2011,[516] and due to cybersecurity's growing importance, we adopt SCE's labor forecast of $7.529 million, bringing the total adopted 2015 C&C forecast to $17.384 million.

9.1.3. Client Services & Planning (CS&P) (Account 920/921)

SCE requests a 2015 CS&P forecast of $15.44 million for Labor and $2.376 million for Non-Labor (total: $17.816 million). This forecast is based on the 2012

[516] SCE-05, Vol. 1 at 52, Figure II-9.

recorded ($19.267 million for Labor and $3.514 million for non-labor; $22.781 million Total) with reductions attributable to OpX savings and an addition of $180 thousand for severance pay.[517] ORA recommends reducing SCE's forecast by 20% to $12.352 million for Labor and $1.901 million for Non-Labor ($14.253 million total).

Of ORA's 20% reduction, 16% is intended to remove historical costs from certain cost centers associated with duplicate activities and SONGS costs.[518] ORA argues that even though one of CS&P's functions is to "minimize duplication,"[519] it has several functions that are "substantially similar to subgroups within other IT divisions."[520] In particular, ORA claims that CS&P data collection and performance monitoring functions are duplicated by the ITS Service Management & Planning (SM&P) group, and the long-term planning and prioritization of technology investment is duplicated by EIMA's Enterprise Architect. SCE explains that while both CS&P and SM&P both perform data collection and performance monitoring functions, they are not duplicative since CS&P "provides this service to all IT divisions for areas that are common activities that they all share as well as summary level reporting" requiring "broad knowledge of how the divisions function and how the data is gathered uniformly across all of IT." SM&P has a narrower function, collecting and analyzing "key operational performance and service level indicators [ ] responsible for ITS unique data that is detailed and technical." SCE also contrasts CS&P and EIMA functions by observing that they are "complimentary, not duplicative. …CS&P personnel gather future business capability needs and turn them into business

[517] *Id*. at 71.
[518] ORA-15 at 14-15.
[519] SCE-05, Vol. 1 at 64.
[520] ORA-15 at 15.

requirements" while EIMA uses "these business requirements to drive technology decisions and directions."[521]

ORA also argues that a portion of its proposed 16% reduction is due to SCE's failure to remove "the SONGS cost center from historical costs."[522] SCE states that "it made every attempt to remove the testimony and forecast costs for SONGS in SCE-14 as directed in the Scoping Memo …The Director costs referenced likely includes a small amount of incremental SONGS related costs that would need to be determined." The referenced "Director SONGS/Power Production" item has a cost of $0.607 million according to SCE's workpapers.[523]

Though ORA states that several CS&P functions are duplicated elsewhere in IT and the forecast should therefore be reduced by 16%, SCE successfully points out that those functions are either complimentary or different in scope, despite having similar descriptions. ORA's examination of functionality by studying descriptors rather than a more detailed look at the actual scope of the work done in each group did not lead us to conclude there was any duplication. As such, SCE's forecast should not be reduced by 16%. ORA, however, was correct in asserting that a small amount of SONGS-related costs were not removed from the historical costs as directed in the Scoping Memo. SCE did not determine what portion of the $0.607 million for "Director SONGS/Power Production" is attributable to SONGS, only that it was a "small amount." We estimate that "small amount" to be $0.150 million and apply that reduction evenly between labor and non-labor.

The other 4% of ORA's overall 20% proposed reduction is due to the productivity and benefits deriving from central planning and gatekeeping

[521] SCE-21 at 10-11.
[522] ORA-15, fn. 43.
[523] Workpapers SCE-05, Vol. 1, Pt. 2 at 169.

functions of CS&P. ORA would like to reduce SCE's CS&P forecast by 4% largely because SCE could show "measurable benefits for only five of its 148 proposed capitalized software projects."[524] However, as SCE points out, "measuring the productivity components [of projects] separately from other drivers is very difficult" and true "productivity projects…are very rare."[525] As such, even if "[p]roductivity should result from the type of coordination, oversight, and gatekeeping function that CS&P provides," as ORA argues, it would be difficult to tease out of the numbers. More frequently, that productivity is incorporated on the front end where, as SCE states, the benefits of the central planning and gatekeeping functions come from "ensuring that the highest value projects are implemented and that standard criteria, including productivity, are used to evaluate and prioritize IT projects."[526] Therefore, since SCE considers productivity and has shown there are benefits, the CS&P forecast should not be reduced by 4%.

We adopt a 2015 CS&P forecast of $15.365 million for Labor and $2.301 million for Non-Labor ($17.666 million total).

9.1.4. Incremental O&M for New Software (Account 920/921)

When SCE has a new software project exceeding $5 million, the recurring O&M support costs are tracked separately as incremental O&M for new capitalized software. Projects are deemed new either because they did not exist before, or they are a new phase (exceeding $5 million) of an existing project.[527] For 2015, SCE forecasts spending $5.204 million for Labor and $3.616 million for Non-Labor ($8.82 million total). ORA recommends $1.555 million for Labor and $1.08 million for Non-Labor ($2.635 million total). SCE's estimates reflect a 59%

[524] ORA-15 at 14-15.
[525] SCE-05, Vol. 1 at 67.
[526] SCE-21 at 12.
[527] SCE-05, Vol. 1 at 71.

to 41% division between labor and non-labor respectively based on the "2012 actual/recorded costs breakdown."[528]

ORA recommended the removal of the incremental O&M costs for any proposed capital software project it argued to disallow in ORA-14, resulting in a 20% reduction to SCE's forecast.[529] SCE does not object to removing O&M costs for any projects the Commission does not approve.[530] We agree with the parties that the incremental O&M costs for rejected or reduced projects should be removed, however we have not rejected or reduced the 2015 costs of any of SCE's listed projects[531] and, accordingly, make no changes to the forecast.

Each year, the applications supported by IT change as some systems are decommissioned and others are added. ORA argues that the savings in support costs from system decommissioning should be netted against incremental O&M for capitalized software and recommends reducing the forecast by the average "O&M labor and non-labor recurring maintenance costs" from 2011 and 2012, i.e. $1.769 million.[532] However, as SCE points out, these "savings were in prior periods [and therefore] would already be reflected in recorded spend" as part of TDM's 920/921 FERC account.[533] As such, reducing the 2015 forecast by that amount would double-count the savings from the decommissioning. Consequently, ORA's $1.769 million reduction to SCE's request should not be adopted.

ORA states that many of SCE's projects here have a history of capital spending and, since those systems "were in service in the historical recorded period, ORA assumes that the historical recorded costs in other parts of IT's

[528] *Id*. at 73.
[529] ORA-15 at 17.
[530] SCE-21 at 14.
[531] SCE-14, Attachment 7 at 74.
[532] ORA-15 at 17-18.
[533] SCE-21 at 14.

testimony include the recurring maintenance costs for those systems" and removes 50% of the forecast to account for those embedded costs.[534] ORA does not, however, provide a list of these projects. Based on SCE's testimony, ORA seems mistaken on this subject. All projects in this category are "new," defined as "projects that implement new functionality that needs to be supported. Even if the project is an expansion of existing systems or applications, additional support will be needed as the new functionality is implemented."[535] Put more succinctly, these are projects "which did not exist in the recorded period"[536] and, as such, cannot have historical recorded costs for recurring maintenance as ORA argues. Without those historical costs, there is no basis for reducing SCE's forecast by 50%. Therefore, ORA's 50% forecast reduction should not be adopted.

To sum up, SCE's forecast should not be reduced by $1.769 million to reflect reduced support costs due to system decommissioning, nor should it be reduced by 50% due to historical support costs. Therefore, we adopt SCE's 2015 forecast of $8.82 million.

9.2. IT – Capital

9.2.1. Reducing 2014 Forecast Due to 2013 Spending

In many instances in this GRC, ORA has recommended reducing 2014 IT forecasts for accounts where the 2013 recorded amount exceeded the 2013 forecast.[537] When ORA has proposed a reduction to 2014 spending "in equal and opposite amount to the amount spent greater than the 2013 forecast, SCE has agreed with this adjustment" since there is frequently a connection between

[534] ORA-15 at 18.
[535] SCE-21 at 14.
[536] SCE-05, Vol. 1 at 72.
[537] SCE-21 at 17, Table II-7.

spending in one year and subsequent years.[538] However, SCE takes issue with ORA's failure to apply this principle in the opposite direction, i.e. SCE believes underspending in one year should be presumed to be followed by an increase in spending in the following year.[539] We agree with the former proposition and disagree with the latter.

An overspend in a prior recorded year typically results in the reduction of the subsequent year's forecast by the amount overspent in order to protect the ratepayers from excessive spending by maintaining the original total forecast. This is a presumption that can be overcome with testimony refuting the need for that reduction. However, the reverse – an underspend in a prior recorded year resulting in an increase in the subsequent year's forecast by the amount underspent – is neither automatic nor assumed. The addition of the underspend to the subsequent year must be justified to ensure the added expense is still necessary. We will evaluate such requests according to these principles in the sections below.

9.2.2. Detailed Tracking of Costs

ORA recommends "that the Commission require SCE to track the different forecast costs to actual costs by the same categories, and any scope changes, and include this information as part of the GRC application. This recommendation would have the effect of making the forecast costs more relevant and improve the forecast accuracy in future GRCs."[540] SCE opposes ORA's recommendation because it "already provides historical costs of all the projects requested in the prior case. We also provide historical costs for every category of IT spend.

[538] *Id*. at 18.
[539] *Id*. at 17.
[540] ORA-14 at 5-6.

…ORA presented no evidence for this assertion [of relevance] or estimate of how much it would cost to provide such information."[541]

Since ORA's request here is only two sentences, it is subject to some interpretation. Nevertheless, it seems that ORA is asking SCE to include in future GRCs (1) historical forecasts and (2) changes in the scope of any category. SCE insists ORA did not demonstrate relevance, but the relevance is inherent in the requested information. Providing historical costs is important, but providing those costs alongside historical forecasts offers greater context for the numbers. For example: $5 million in recorded costs for 2010 is helpful information, but not as helpful as also knowing that the approved forecast for that year was $1 million. Such context is naturally relevant. Similarly, any changes in a category's scope would also provide necessary context. For instance, if the longstanding category of widgets now includes not just widgets, but widgets *and* widget plug adapters, that is necessary context to better understand the numbers in recorded costs as well as past and future forecasts. SCE's concern over the potential costs to provide such information is understandable, but overstated: all the information requested by ORA should be available in previous GRCs, which SCE assuredly already reviews when putting together its current GRC. Therefore, in future GRCs, we find it reasonable to require SCE to include its own forecast and the Commission's adopted forecast from the previous GRC alongside historical costs, and brief explanations detailing any changes in the scope of a category.

9.2.3. Midrange Enterprise Servers Hardware/Alhambra Data Center

In SCE's forecast request for Midrange Enterprise Servers Hardware, there is a budget line item for the "Alhambra Data Center Forecast." SCE's 2015 forecast for this line item is $13.6 million while ORA recommends $1.6 million.

[541] SCE-21 at 20.

ORA argues that since the new Alhambra Data Center addition will not begin construction until 2016, "ORA recommends removing the associated IT capital costs from 2015."[542] ORA does not assert that the Data Center expansion is unnecessary, just that most of the work is unnecessary in 2015. SCE counters that the 2016 construction start date used by ORA is a reflection of SCE's Corporate Real Estate team needing to specify actual construction of the physical facilities, while the "$12 million that IT will spend on the Data Center project in 2015 is for planning, detailed design, and pre-staging activities for the servers and supporting infrastructure (e.g. racks) that will go into the newly expanded data center. These server related planning activities do not require the Data Center physical expansion to be complete."[543] Moreover, the build out of the Data Center is needed to accommodate the influx of new data from the expansion of the SmartMeter program.[544] Therefore, since SCE has demonstrated that the Alhambra Data Center project is necessary and, despite the 2016 construction start date, expenditures in 2015 are appropriate as part of planning, designing, and pre-staging the Center's servers and infrastructure, we approve SCE's $13.6 million forecast for the Alhambra Data Center. As ORA and SCE do not disagree about any other elements of the 2015 forecast for Midrange Enterprise Servers Hardware, we adopt SCE's 2015 forecast of $39.504 million.

9.2.4. Personal Computers – Desktop/Notebook and Ruggedized Laptops Refresh/Replacement

The following table details the relevant 2013, 2014, and 2015 forecasts by SCE and ORA as well as the 2013 recorded costs (millions of nominal$): [545]

[542] ORA-14 at 8.
[543] SCE-2 at 22-23.
[544] SCE-08, Vol. 3, Part 2 at 44.
[545] SCE originally forecast $8.725 million for 2014 but requested to change it to $10.347 million in its Opening Brief, which is reflected in this table. ORA did not comment on this change in its Opening or Reply Briefs. SCE Brief at 197. *See also* SCE-05, Vol. 1 at 95; ORA-14 at 11.

	2013 Recorded	2013 Forecast	2014 Forecast	2015 Forecast
SCE	$9.728	$11.350	$10.347	$9.128
ORA			$7.132	$8.538

There are two issues here: (1) ORA characterizing SCE's 2013 recorded expenditures as an overspend while SCE characterizes it as an underspend, and then both parties applying that difference to the 2014 forecast; and (2) the quantification of SCE staff reductions. Each issue will be addressed separately.

SCE forecast $11.35 million for 2013 but recorded $9.728 million.[546] On its face, this is an underspend of $1.622 million. SCE added the $1.622 million to its original 2014 forecast of $8.725 million to get a final forecast of $10.347 million.[547] SCE justified the carryover on the grounds that the underspend occurred due to "delays in timing or refreshing devices" and that the "need for refreshing [those] devices still exists."[548] On the other hand, ORA claims "the 2013 actual exceeded SCE's 2013 forecast," but provides no explanation about how it arrived at a conclusion contrary to the numbers.[549] SCE explains in its rebuttal testimony that ORA "focused on discrete components of the PC and Ruggedized Laptop refresh, selected the one component where there was overspending and reduced by that amount."[550] Examining the underspending and overspending of individual line items and then correspondingly adjusting the forecast can be appropriate, but not without further explanation for each adjusted item. Therefore, as SCE argues, "[t]he adjustment that should be made to 2014 is the net, not a selective

[546] SCE-21 at 24.
[547] SCE Opening Brief at 197.
[548] SCE-21 at 25.
[549] ORA-14 at 10.
[550] SCE-21 at 25.

adjustment."[551] Since SCE's need to refresh additional computers was due to delays in 2013 and this need is recurring, adding the 2013 underspend to the original 2014 forecast is reasonable and, therefore, adopted.

ORA also recommends reducing the 2014 and 2015 forecasts by 10% each based on a 2014 Los Angeles Times article which states that SCE plans to reduce its workforce by 11.4%.[552] Though ORA did not independently verify the information in the article, sources quoted in the article include then State Senator and current California Secretary of State Alex Padilla and SCE itself (confirming the existence of layoffs but not the number of people affected).[553] Later, during evidentiary hearings, SCE witnesses confirmed staffing reductions of 1,100 employees at SONGS alone.[554] SCE rejects ORA's 10% reduction because its use of the LA Times article lacks independent verification, ORA doesn't consider SCE's OpX reductions, and SCE's own estimates are "based upon SCE's current workforce projections."[555] SCE's workforce projections were used consistently in a variety of areas of this case.[556] Therefore, we reject ORA's proposed rejection and adopt SCE's forecast. Nevertheless, SCE's forecast could have and should have been more transparent in this regard. Therefore, we require that SCE document its headcount forecast in all future General Rate Cases and show how that headcount forecast is applied in any cost forecast that relies on it.

9.2.5. Transmission Network Facilities

The Transmission Network Facilities budget provides for the life-cycle replacement of obsolete, failed, and damaged telecommunications network

[551] *Id*.
[552] ORA-14 at 10-11.
[553] Los Angeles Times, April 15, 2014 "SoCalEdison to lay off hundreds in effort to streamline Management." *See also* ORA-14 at 10-11.
[554] SCE/Inlander, 10 RT 992 lines 1 – 5.
[555] SCE-21 at 25.
[556] See: SCE-10V2 and SCE-8V3P1 at 5)

equipment.[557] SCE's original testimony (SCE-05) on Transmission Network Facilities was supplemented by SCE-16,[558] which updated recorded and forecast numbers for this item due to the inadvertent failure to include testimony for the Netcomm Radios line item.[559] ORA does not appear to have accounted for the changes made in SCE-16.[560] Nevertheless, since ORA recommends using a five-year recorded cost average to calculate the forecast, that methodology can be considered even if ORA's numbers cannot. SCE disagrees with the use of the averaging methodology.

Since so many changes occurred between SCE-05, SCE-16, and SCE-21, it is instructive to first review the numbers in one consolidated table:

SCE Recorded (in millions)						**SCE Forecast (in millions)**			
2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
$14.68	$16.48	$16.64	$15.13	$14.43	$13.35	$25.40	$23.81	$23.94	$24.17
* $17.85 was SCE's original forecast for 2013					($17.85*)	($20.90*)	* $20.90 was SCE's original forecast for 2014		

The original 2013 forecast was $17.85 million so SCE added the $4.503 million underspend from that year to the original 2014 forecast to come up with a final request of $25.403 million.

ORA argues for the use of a 5YA of recorded costs since they had shown "a clear downward trend" during that time.[561] On the other hand, SCE argues that there was a 275% rate of increase in data traffic from 2012-2014, a trend it expects to continue, and that a 5YA would not account for such rapid growth.[562] SCE does not offer evidence supporting its assertion that data traffic increased by 275% nor any specifics supporting the continuation of that "trend." Even if we

[557] SCE-05, Vol. 1 at 105.
[558] SCE-16, Appendix A at A-13 – A-18.
[559] SCE-21 at 27.
[560] ORA-14, pp. 13-14; ORA Opening Brief at 236-237.
[561] ORA-14 at 13.
[562] SCE-21 at 28.

accept the 275% at face value,[563] SCE has not demonstrated a link between an increase in data traffic and a need for an increased budget, as SCE's recorded amounts in 2012 and 2013 indicate a 7.5% decrease in expenditures. Indeed, 2013 marked the fourth consecutive year of decreased expenditures in this category. This running decrease is more notable since, according to SCE, expenditures all the way back to 2010 have been "more than typical years with increases to support increased network capacity to our data network hubs that support all the users of SCE's data network."[564] In other words, the need for expanded network capacity to accommodate increased data traffic has existed for several years without resulting in an increase in actual expenditures. Nevertheless, SCE seeks a 43% increase in its requested forecast here.[565] Without a demonstrated need for increased expenditures, SCE's forecasts are unjustified as is its request to add the 2013 underspend to the 2014 forecast. Therefore, since SCE's spending in this category will address expenditures typical for the last five years, ORA's five-year recorded cost average methodology better calculates the appropriate forecasts. ORA calculated the average between 2009 and 2013;[566] however we calculate the average from 2008 to 2012 in order to remain consistent with the application of averaging elsewhere in this GRC. Applying this methodology to SCE's 2008-2012 numbers, we adopt a Transmission Network Facilities forecast of $15.471 million for both 2014 and 2015.

[563] In D.14-08-032 at 499, the Commission accepted PG&E's assertion that their bandwidth would grow by 300% over the next 5-10 years.
[564] SCE-05, Vol. 1 at 108.
[565] SCE-16, Appendix B at B-42.
[566] ORA-14 at 13-14.

9.2.6. Fiber Cable Replacement

Fiber Optic Cable Replacement provides for the replacement of aging or failing fiber optic cables.[567] In SCE's direct testimony, it requested forecasts of $2 million for 2013, $1.2322 million for 2014, and $4.400 million for 2015.[568] When SCE recorded only $0.189 million in 2013, it adjusted its 2014 forecast by adding the $1.811 million underspend from 2013, resulting in a new 2014 forecast of $3.043 million.[569] Also of note, SCE recorded $0.936 million in 2012 versus a $5.148 million forecast.[570] ORA recommends forecasts of $1.232 million for 2014 and $1.620 million for 2015.[571]

SCE states that it wants to focus on replacing 188 miles of its oldest fiber cable by 2017 due to obsolescence.[572] It planned to replace 27 miles of cable in 2013, 16 miles in 2014, and 59 in 2015, while removing 25, 18, and 58 miles respectively.[573] SCE also states that its forecasts are achievable even if they seem to be "escalating quickly [since] [m]ost of the work is done by contractors that are overseen and managed by SCE and therefore manpower should not be a constraint."[574] However, as ORA noted,[575] SCE has not demonstrated an ability to fulfill its past forecasts: its 2012 forecast was intended to replace about 100 miles of cable for $5.148 million but SCE only spent $0.936 million;[576] in 2013 it forecast $2.0 million but only spent $0.189 million. Based on those numbers, SCE removed/replaced an estimated 21 out of 127 miles, or 17%, of cable.[577] Notably,

[567] SCE-05, Vol. at 115.
[568] *Id*. at 117.
[569] SCE-21 at 30.
[570] D.12-11-051 at 404-405.
[571] ORA-14 at 16.
[572] SCE-05, Vol. 1 at 116.
[573] Workpaper SCE-05, Vol. 1, Ch. 3 at 128.
[574] SCE-21 at 30.
[575] ORA-14 at 17.
[576] D.12-11-051 at 404-405.
[577] (0.936/5.148) X 100 miles = 18 miles; (0.189/2.0) X 27 = 3 miles; 18 + 3 = 21 miles.

SCE's recorded amount dropped by 80% from 2012 to 2013 even though it had already been slowed by permitting problems in 2012, and the recorded amount in 2012 was relatively small to begin with.[578] Out of more than $7 million forecast over those two years, SCE only spent 16% of that amount which is inconsistent with an "expeditious" need to replace obsolete cable.[579] As such, SCE's stated desire to expeditiously replace 188 miles of "obsolete" fiber cable has, to date, not been matched by its actions.

ORA takes a more reasonable approach with its recommendations. For 2015, ORA recommends a forecast of $1.620 million, an amount based on the installation and removal of 21.5 miles of fiber cables, i.e. the average of the 27 miles and 16 miles of cable scheduled for installation/removal by SCE in 2013 and 2014.[580] We find ORA's approach more appropriate and adopt its forecast of $1.620 million for 2015.

For 2014, ORA recommended $1.232 million, the same amount SCE requested in its original testimony.[581] Since SCE intended to install 16 miles of cable and remove 18 miles in 2014, both below average, and SCE underspent in 2013, we believe it appropriate to approve more than the $1.232 million recommended by ORA. However, due to SCE's demonstrated difficulties fulfilling its forecasts in this area, we cannot approve SCE's $3.043 million request, an amount that essentially follows ORA's approach discussed above. Instead, we take a measured approach in order to allow SCE the funding to install and remove the intended amount for 2014 as well as a portion of what it

[578] SCE-05, Vol. 1 at 117.
[579] *Id*.
[580] ORA-14 at 17. SCE's Workpaper, SCE-05, Vol. 1, Ch. 3 at 128, prices fiber optic cable installation at $60,000/mile and removal at $15,000/mile: (21.5 X 60K) + (21.5 X $15K) = $1.62 million.
[581] ORA-14 at 17.

intended to install and remove in 2013. Accordingly, we adopt the original 2013 forecast of $2.0 million for 2014.

9.2.7. Microwave Replacement

SCE requested $9.905 million for 2014 and $6.5 million for 2015, while ORA recommended $2.475 million for each year.[582] Additionally, SCE originally forecast $6.5 million for 2013 but ultimately recorded only $3.1 million. SCE also originally forecast $6.5 million for 2014, but requested that the "2014 forecast be revised to $9.9 million to account for the amount that the 2013 recorded was less than the 2013 forecast."[583] SCE's present cost per microwave replacement unit is $0.165 million.[584]

Since SCE started replacing its microwave equipment in 2009, it has only replaced between 13 and 21 units in any given year; it now seeks to replace 40 units per year.[585] Even though SCE states its "work is governed by the available funding" and it could therefore replace 40 units/year if only it had the money to do so, its authorized amount of $7.8 million in 2012[586] as compared to its recorded expenditure of only $2.25 million for 13 units in 2012,[587] and a requested $6.5 million for 2013 versus a recorded $3.1 million suggests otherwise,[588] raising doubts as to whether SCE is truly interested in or capable of replacing 40 units in one year in the first place. Moreover, though SCE never explicitly states this, its request for $9.905 million in 2014 suggests SCE believes it can replace 60 units,[589] a number of replacements it has never approached, attempted, or requested. In

[582] SCE-21 at 31.
[583] *Id*.
[584] Workpaper "Project Cost Estimating Summary – Microwave Replacements," SCE-05, Vol. 1, Ch. 3 at 134.
[585] ORA-14 at 18.
[586] D.12-11-051 at 400.
[587] SCE-05, Vol. 1 at 119.
[588] SCE-21 at 31.
[589] $9.905 million/$0.165 million per unit = 60 units.

past and future cases, SCE states that replacement occurs to address "obsolete, failed, and damaged microwave equipment," however SCE has not stated a reason for its increased request to replace 40 units/year, nor has it presented any evidence to support a need for it.[590] As such, SCE's requests for $9.905 million in 2014 and $6.5 million in 2015 appear unsupported by the record.

ORA has recommended a forecast of $2.475 million for both 2014 and 2015 based on replacing 15 units per year at SCE's stated cost per unit of $165,000. We find ORA's per unit methodology to be sensible, but since SCE's average number of replaced units per year 2009 through 2013 was 16,[591] we adopt 2014 and 2015 forecasts of $2.640 million each to reflect that average.

9.2.8. Mobile Radio System Replacement

SCE and ORA agree that the 2014 forecast should be reduced by SCE's 2013 forecast overspend. The two disagree over whether SCE's 2014 and 2015 forecasts should also be reduced by the same 10% discussed above in Personal Computers, a reduction based on a 2014 Los Angeles Times article. Though SCE rejects the article,[592] the accuracy of the claimed 11.4% reduction in SCE's workforce appears to be beside the point here as the purported SCE employees subject to layoffs or outsourcing are not the ones stationed in the field using the mobile radio system.[593] Even the LA Times article points out that most of the job losses will be at either SONGS or SCE's "sprawling Irwindale office complex." Since the 10% reduction does not appear to impact the "field force" users of the mobile radio system, ORA's 10% reduction to SCE's forecasts should be rejected here. Furthermore, since ORA does not otherwise object, SCE's forecasts of $4.601 million for 2014 and $14 million for 2015 are hereby adopted.

[590] SCE-05, Vol. 1 at 118-120.
[591] ORA-14 at 18.
[592] *See* Personal Computers section above for a discussion of the article's efficacy.
[593] SCE-21 at 33; SCE-01 at 8.

9.2.9. Risk Management Disaster Recovery

SCE requests an increase in disaster recovery spending to $3.474 million in 2014 and $4.1 million for 2015, levels well above its previous expenditures in this category, while ORA recommends applying a 5YA of recorded costs from 2009-2013 to reflect SCE's actual spending: $2.549 million for both 2014 and 2015.[594] SCE argues that ORA's cost-average approach might be appropriate if SCE were only refreshing existing disaster recovery systems, but that it does not account for the need to enhance SCE's recovery capabilities.[595] However, SCE also describes its expenditures from 2008-2012 as "primarily driven by refresh of disaster recovery hardware at the end of its useful life for the period 2008 to 2012. In addition, disaster recovery hardware was acquired to enhance disaster recovery capabilities for a number of key business systems."[596] As such, averaging those costs would still take into account SCE's stated need for both refreshing *and* enhancing its disaster recovery systems. Moreover, an examination of SCE's workpapers shows no delineation between "refresh" items and "enhancement" items; indeed, *all* items listed in the workpapers are subtotaled or totaled as "refresh" items.[597] Therefore, according to SCE's own reasoning, ORA's five-year recorded cost average is the most appropriate methodology and should be adopted, in addition to being more reflective of SCE's actual expenditures.[598] We adopt ORA's forecast of $2.549 million for both 2014 and 2015.

[594] SCE-21 at 33-34; ORA-14 at 21-22.
[595] SCE-21 at 33-34.
[596] SCE-05, Vol. 1 at 125-126.
[597] Workpaper SCE-05, V1, Ch. 3 at 146.
[598] *See* ORA-14 at 21-22.

9.2.10. Telecom Costs for Projects

There are 92 discrete telecommunication projects requested in this GRC, for which SCE requested forecast spending of $43.046 million in 2014 and $51.756 million in 2015.[599] ORA recommends $35.26 million for 2014 and $40.8 million for 2015. The primary differences between the two requests is that both parties disagree about the inclusion of a $26.3 million line item for "[Corporate Real Estate] CRE Projects" and whether or not a "least-squares trend" should be used to calculate the forecast.[600] Each issue will be addressed in turn.

As a result of ORA data requests in February 2014, SCE realized it had "inadvertently left out referencing the telecom portion of [twelve] project costs in various exhibits, and had not included the material necessary to support the missing costs in workpapers."[601] Forecast costs for the twelve project line items, however, were included in both the overall IT telecom request totals and the Results of Operations model, with prepared testimony supporting the associated projects.[602] SCE reviewed each of the twelve line items, dropped three of them from its request, and adjusted the forecasts for others resulting in a $20 million reduction in its overall telecom forecast.[603] SCE submitted errata, supplemental testimony, and data responses to address these oversights. However, one of the line items – CRE Projects (CIT-00-OP-NS-000154) – was addressed via "incremental testimony" in SCE-14 due to its sizable cost of $26.3 million.[604] SCE-14 was submitted on April 7, 2014 and explained that the $26.3 million in telecom costs are necessary since "[p]roviding IT equipment and infrastructure at our new and existing non-electric facilities is an essential part of optimizing use

[599] SCE-16.
[600] ORA-14 at 70-71.
[601] SCE-16 at 2.
[602] *Id*. at 3.
[603] *Id*. at 4.
[604] *Id*.

of such facilities by SCE personnel."[605] Additionally, SCE is moving out of leased office space into SCE-owned space that it must now outfit with new equipment to support its staff.[606] SCE's forecast of $26.3 million for this line item is based on the number of planned projects and the "average ratio of historical IT expenditures to the total annual recorded costs respectively."[607] The $26.3 million in forecast expenditures was not "included in the capital project cost estimates discussed in other testimony and related workpapers (e.g. the project planning estimates)."[608]

ORA recommends the Commission "reject" the $26.3 million on procedural grounds. ORA points out that page seven of the Joint Scoping Memo states all parties are "responsible for making their case in their direct testimony and pleadings, not in rebuttal or during hearings." ORA additionally notes that Rule 13.8(b) of the Rules of Practice and Procedure provides that "Direct testimony in addition to the prepared testimony previously served, other than the correction of minor typographical or wording errors that do not alter the substance of the prepared testimony, will not be accepted into evidence unless the sponsoring party shows good cause why the additional testimony could not have been served with the prepared testimony or should otherwise be admitted." SCE admitted the failure to include testimony on the $26.3 million was inadvertent, which ORA argues "should not be considered good cause" and that "SCE should not be given a 'second bite of the apple.'"[609]

By a strict interpretation of the Scoping Memo and Rules of Practice and Procedure, it is possible to view SCE's submissions as additional direct testimony

[605] SCE-14, Attachment 14 at 78a.
[606] *Id.*
[607] *Id.*
[608] *Id.*
[609] ORA Opening Brief at 230.

and, generally speaking, simply forgetting to include testimony would not be considered "good cause." However, in this case, during the July 18, 2014 Status Conference, the Commission specifically addressed the submission of supplemental testimony regarding the telecom projects, stating that while timely submission of testimony is important and "[e]rrata should be limited to correcting small errors…not providing a significant showing for the first time…we do recognize that in a huge case like this, many people are involved and it is possible for some things to be missed."[610] SCE was given until July 28, 2014 to submit additional testimony, but those days were unnecessary as SCE-14 had already been submitted on April 7th. Moreover, since SCE-14 was submitted nearly four months in advance of ORA's IT Capital analysis in ORA-14 and seven months in advance of its opening brief, ORA was not prejudiced by the delay in the submission of the $26.3 million in costs. Therefore, since the procedural delays did not prejudice ORA and there are no substantive objections to the CRE Projects, that line item should not be rejected.

ORA also examined the actual expenditures from 2009-2013 for the telecom projects and concluded that "because a clear trend exists," a least-squares trend should be applied to the forecast. SCE disagrees, noting that the historical data used by ORA to develop its forecast is incomplete.[611] Additionally, the least-squares methodology "is a regression against time, treating telecom costs as a stand-alone item, independent of projects."[612] SCE's telecom forecasts here are tied directly to their individual projects; i.e. the forecast costs go up or down depending on the number and size of the projects each year. Using a least-squares trend for the forecast would ignore this and result in future

[610] July 18, 2014 Status Conference, Transcript Vol. 5 at 208-209.
[611] SCE-21 at 67.
[612] *Id.* at 68.

forecasts being tethered to "historical data" rather than the actual proposed projects. As such, a least-squares trend would be inappropriate here. As SCE states, "whether the Commission approves or rejects funding for any of these telecom requests should be based on the value of the underlying business project as they have in past rate cases."[613] Consequently, since there is no disagreement between SCE and ORA over the necessity, scope, or cost of any of the individual telecom projects (save for the $26.3 million CRE Projects already discussed above), we adopt SCE's forecast of $43.046 million for 2014 and $51.756 million for 2015.

9.3. IT – Capitalized Software

9.3.1. Software Asset Management (SAM) Bundles

9.3.1.1. ORA's 34% SAM Reduction

In the 2012 SCE GRC, the Commission approved funding for a collection of thirty-six capitalized software projects grouped together under the title SAM Bundle.[614] Generally, projects in the SAM Bundle prioritized "software upgrades and replacements to mitigate risks due to security problems, technology obsolescence, and application failure."[615] Of the thirty-six projects in the 2012 SAM Bundle, SCE requested funding for ten of them in this general rate case.[616]

ORA examined the 2010-2012 SAM Bundle and determined that while $100.963 million was authorized, the total recorded was only $66.706 million (ORA-14, p. 31). Based on this $34.257 million difference, ORA recommended that all projects in the 2014-2015 SAM Bundle "be reduced by 34% to reflect the actual to authorized variance experienced by SCE for the 2010 to 2012 period."

[613] *Id.* at 67.
[614] D.12-11-051 at 412-425.
[615] *Id.* at 412.
[616] ORA-14 at 31; SCE-21 at 19-20.

(*id*.) This 34% reduction was then applied to forecasts for the following projects: Consolidated Mobile Solution (CMS), Design Manager Refresh, Enterprise Core Platform Refresh, GE Smallworld Refresh, Integrated Work Management System and related Systems Upgrade, Renewable Contract Management System, Scheduling Refresh, and Usage Measurement System.[617] Despite its recommendation, ORA did not object to any of the SAM Bundle projects on their merits.

ORA's across the board 34% cut should not be adopted. Each of the projects in the SAM bundle was approved in the 2012 GRC. Their inclusion in the 2015 GRC reflects reevaluations of the projects and, in some cases, delays in their implementation.[618] ORA has not objected to any of the projects on the merits; rather it asks for a 34% cut because SCE underspent by that amount on the SAM Bundle from 2010-2012. Were such an across the board cut proposed based on the merits of the projects or a demonstrated pattern of over-forecasting/underspending, then perhaps it would warrant consideration. However, here, the cut is proposed for neither reason. As SCE explains, the underspend was due largely to a planned reduction in non-essential and non-safety-related spending since the 2012 GRC was not concluded until that December.[619] The projects, in turn, still require completion but on the new schedule reflected in the forecasts. As such, ORA's 34% across the board reduction should not be adopted with regard to any of these SAM Bundle projects: CMS, Design Manager Refresh, Enterprise Core Platform Refresh, GE Smallworld Refresh, Integrated Work Management System and related Systems

[617] Respectively, SCE-05, Vol. 2, Pt. 2 at 56; SCE-05, Vol. 2, Pt. 2 at 47; SCE-05, Vol. 2, Pt. 1 at 68; SCE-05, Vol. 2, Pt. 2 at 53; SCE-05, Vol. 2, Pt. 1 at 93; SCE-05, Vol. 2, Pt. 1 at 203; SCE-05, Vol. 2, Pt. 2 at 45; and SCE-05, Vol. 2, Pt. 1 at 210.
[618] SCE-05, V2, Pt. 1 at 203 and 210; SCE-21 at 61 and 69.
[619] SCE-21 at 19-20.

Upgrade, Renewable Contract Management System, Scheduling Refresh, and Usage Measurement System. The adopted 2014-2015 forecasts for these projects are listed in the table below with explanations for the Renewable Contract Management System (RCMS) and CMS forecasts following (millions of nominal$):

SAM Projects	2014	2015
Consolidated Mobile Solution	$5.424	0
SAM - Design Manager Refresh	$1.625	0
Enterprise Core Platform Refresh	$1.067	$4.610
SAM - GE Smallworld Refresh	0	$1.300
Integrated Work Management System	$3.360	0
Renewable Contract Management System	$12.520	$7.305
SAM - Scheduling Refresh	$5.400	$2.500
Usage Measurement System	0	$1.500
Total	$29.396	$17.215

9.3.1.2. Renewable Contract Management System

In addition to reducing the 2014 RCMS forecast by $5.277 million for the across the board 34% reduction discussed above, ORA recommended reducing the total 2013-2015 RCMS forecast of $20.52 million by another $4.305 million due to unspent 2013 budget. SCE's original and adjusted forecasts as well as ORA's recommendations are listed in the table below:

	2013	2014	2015
SCE Original	$5 million	$15.520 million	$0
SCE Adjusted	$0.695 million	$12.520 million	$7.305 million
ORA Recommended	$0.695 million	$10.243 million	$0

ORA offers no explanation for its $4.305 million reduction to the project total.[620] SCE explains that RCMS was included in the 2012 GRC,[621] but was

[620] ORA-14 at 55.
[621] SCE-05, Vol. 2, Pt. 1 at 204.

delayed in order to "enlist the services of a qualified and experienced system integrator consultant to help implement the system. System integrator consultants are commonly used across the industry to help implement projects of this nature."[622] Even though this meant work on the project was delayed, the scope of work was not reduced.[623] As a result, the full $20.520 million funding need remains unchanged. As discussed previously, adding the underspend from one year to subsequent forecast years requires justification. Since SCE has demonstrated that the underspend was due to a reasonable delay, total project spending remains unchanged, and the forecast changes only reflect changes in the project's timing, SCE's adjusted forecast is adopted.

9.3.1.3. Consolidated Mobile Solution

In 2013, SCE overspent its forecast for CMS by $1.608 million. ORA recommended reducing the 2014 CMS forecast by that amount in order to remain consistent with its total project forecast.[624] SCE disagreed and requested $7.032 million for 2014.[625]

ORA's recommendation to reduce the 2014 CMS forecast is reasonable since it maintains the total project spending and SCE offered no explanation to justify increasing its project expenses. Therefore, the adopted 2014 CMS forecast is $5.424 million.

9.3.1.4. Cybersecurity and IT Compliance

ORA recommends reducing SCE's Original 2014 Cybersecurity and IT Compliance forecast by $2.63 million[626] to account for SCE's 2013 overspend in the Interior Defense sub-account while ignoring that three other sub-accounts –

[622] SCE-21 at 61.
[623] *Id*.
[624] ORA-14 at 68.
[625] SCE-05, Vol. 2, Pt. 2 at 56; SCE-21 at 68.
[626] SCE-05, Vol. 2, Pt. 1 at 6-30.

Perimeter Defense, Data Protection, and Common Cybersecurity Services – all underspent in 2013 and the account as a whole had a net underspend of $1.796 million.[627] SCE's revised forecast asks to increase its original $20.340 million forecast for 2014 by $1.79 million (SCE slightly miscalculated: the net is actually $1.796 million) to $22.130 million to account for the 2013 net underspend.[628] As stated, "SCE is willing to stipulate to a decrease in 2014 due to overspend in 2013 as long as the reciprocal is true."[629] As discussed previously, an overspend in a prior recorded year typically results in the reduction of the subsequent year's forecast while the reverse – an underspend in a prior recorded year resulting in an increase in the subsequent year's forecast by the amount underspent – is neither automatic nor assumed. The latter proposition requires justification to protect the ratepayers from unnecessary spending. When SCE made a similar proposition above regarding Personal Computers, the increase in spending was justified by delays in procurement and an ongoing need to refresh the devices. No justification has been offered here; SCE's demand for an increase exists only by virtue of the existence of the underspend.[630] Since SCE has failed to justify its request for an increase in its original forecast and accepts the reduction of the 2014 Interior Defense sub-account due to a 2013 overspend, ORA's recommended forecast is adopted with the following adjustment: ORA reduced the 2014 forecast for the Data Protection sub-account by $500 to $6.2715 million without any explanation; that amount is restored to $6.272 million as originally proposed by SCE. This results in an adopted 2014 forecast totaling $17.711 million, broken down as follows: Interior Defense – $0.590 million; Perimeter

[627] ORA-14 at 25.
[628] SCE-21 at 36.
[629] *Id*.
[630] SCE-21 at 36.

Defense – $5.509 million; Data Protection – $6.272 million; Common Cybersecurity Services – $5.339 million; and Emerging Legislative Mandates – $0.

9.3.2. Regulatory Mandates

ORA recommends reducing SCE's forecast for 2014 and 2015 to reflect a five-year average. As discussed previously regarding the Infrastructure Technology Services Forecast, averaging is an appropriate methodology when there are significant fluctuations in recorded expenses from year-to-year. Given that the recorded costs here show substantial variation in expenses from 2009-2013,[631] averaging would usually be appropriate. However, in this instance, averaging would ignore a significant change in circumstances. Regulatory Mandates reflect a need for SCE to comply with the NERC mandated CIP standards.[632] A revised definition impacting the CIP scope went into effect in April 2013 and auditable compliance for CIP Version 5 will be required by early 2016.[633] This new version coupled with the revised definition "will significantly broaden the scope of assets and controls requiring compliance with CIP standards" and "[t]he number of facilities and assets in-scope for compliance is estimated to be nine to ten times compared to that of Version 4."[634] Moreover, due to the prolonged process of developing these new standards, SCE deferred a "major portion of [its] capital funding from the years 2010-2012 to the years 2014-2017 based on the understanding that CIP Version 5" would go into effect then (*id.* at p. 42). Since using an averaging methodology could not take these changed circumstances into account and SCE presented ample evidence about those changes and their impacts, SCE's forecast of $6.526 million in 2014 and $7 million in 2015 is adopted.

[631] ORA-14 at 27.
[632] SCE-05, Vol. 2, Pt. 1 at 34.
[633] *Id*.
[634] *Id*. at 35.

9.3.3. Other Capitalized Software

9.3.3.1. Safety, Security & Compliance: Master Access Project (MAP)

The MAP will implement new processes and common controls that improve access management and provide compliance with NERC CIP Version 5 by April 1, 2016.[635] SCE originally forecast expenses of $10.55 million for 2013 and $1.806 million for 2014. SCE's actual recorded costs for 2013 were only $1.859 million (just 18% of the initial forecast) due to delays resulting from "bringing on a new implementation partner to complete the project, which has also helped…to lower the project costs."[636] Since SCE still needs to comply with NERC CIP Version 5 and therefore must complete the project, SCE adjusted its 2014 request to $6.794 million.[637] This amount is greater than the original 2014 request, but lowers the project's overall cost from the original request of $12.356 million to $8.652 million, a 30% reduction.[638] ORA recommended using SCE's original $1.806 million forecast for 2014.[639] While ORA offers no objections to the project, it does not acknowledge the need to carry the underspend from 2013 into 2014 – even at a reduced amount – in order to complete the project.[640] Since SCE demonstrated that the project is necessary and the (reduced) underspend will be applied to the project's completion, we adopt SCE's $6.794 million forecast for 2014.

9.3.3.2. Financial Services

SCE revised its forecast due to lower actual recorded costs for 2013, with its 2014 forecast adjusted to $0.500 million and the 2015 forecast to $1.612

[635] SCE-21 at 39; *see also* discussion above in Regulatory Mandates.
[636] SCE-21 at 40.
[637] *Id*.
[638] *Id*.
[639] ORA-14 at 35.
[640] *Id*.

million.[641] In its brief, ORA accepts this revised forecast.[642] We find SCE's uncontested, revised forecast reasonable and it is adopted.

9.3.3.3. Electronic Document Management/Records Management (eDMRM)

SCE requests $11.4 million for eDMRM in 2015.[643] ORA "does not oppose SCE's request" but "recommends that SCE's forecast for 2015 be reduced by $2.850 million, the amount assigned to SONGS."[644] ORA offers no details explaining this recommendation. SCE noted in its initial testimony that the document management systems for SONGS were being decommissioned since they no longer had vendor support, and that SCE planned to "migrate documents from those legacy systems into eDMRM."[645] Moreover, even though the SONGS facility has ended its generating capabilities, that shutdown has not ended SCE's "requirement to maintain SONGS records for compliance with the company's Records Retention Schedule, or to provide access to documents in response to ongoing and future regulatory and legal proceedings or inquiries."[646] Since maintenance of SONGS records is necessary despite the SONGS shutdown, there is no reason to exclude it from the forecast. Therefore, the Commission adopts SCE's request of $11.4 million for 2015.

9.3.3.4. Customer Service – Digital Experience Project

For the Digital Experience Project, SCE requests $8.44 million and $22.3 million for 2014 and 2015 respectively.[647] ORA, on the other hand, recommends

[641] SCE-21 at 40-41.
[642] ORA Opening Brief at 247.
[643] SCE-21 at 42.
[644] ORA-14 at 42.
[645] SCE-05, Vol. 2, Pt. 1 at 105.
[646] SCE-21 at 47.
[647] *Id*. at 51.

rejecting the project, i.e. $0 for 2014 and 2015.[648] ORA's rejection of the project rests on several issues which we will address in turn.

First, ORA strongly disagrees with SCE's benefit-cost ratio estimate and, since ORA determines that the project's costs outweigh the benefits, it recommends the Commission not fund this program.[649] SCE's original benefit-cost analysis resulted in a 1.96 ratio.[650] A revised ratio based on adjustments in response to some of ORA's criticisms resulted in a 1.70 ratio.[651] ORA made its own adjustments to the ratio and calculated it to be only 0.46.[652]

At the core of ORA's disagreement is SCE's use of "phantom avoided costs…that will likely occur if SCE does not implement the full Digital Experience Program."[653] The avoided costs are the potential penalties from violations of two laws: the Controlling the Assault of Non-Solicited Pornography and Marketing (CANSPAM) Act of 2003 and the Telephone Consumer Protection Act (TCPA) of 1991. These laws deal with electronic and telephonic communication and include penalties for violations. SCE estimates the cost of avoided violations at $99.9 million for the next eight years, based on assuming $500 per incident and a three percent risk of occurrence. ORA not only believes that CANSPAM "is not complicated" to follow, but that SCE's estimates of "avoided costs for the next eight years assumes that SCE would not take corrective actions if SCE was notified of a violation, i.e., SCE keeps breaking the law even after being notified."[654]

[648] ORA-14 at 47 – 50.
[649] *Id*. at 48.
[650] SCE-05, Vol. 2, Pt. 1 at 142.
[651] SCE-21 at 55-56.
[652] ORA-14 at 49.
[653] SCE-05, Vol. 2, Pt. 1 at 145.
[654] ORA-14 at 48-49.

However, ORA misconstrues the logistics of a violation. As ORA presents it, violations occur in sequence and can be halted once a customer raises a red flag with a complaint, thereby ending the violation and any associated costs.[655] But, as SCE demonstrated through its cited cases, violations typically involve a single e-mail, text message, or phone call sent to tens, or even hundreds, of thousands of consumers/customers, which is subsequently deemed a violation of CANSPAM or TCPA.[656] The concern is not the $500 cost of a single violation per se, but that amount multiplied by the tens of thousands of recipients. A violating message sent to just 2,000 people could result in costs of $1 million. Considering SCE estimates it will send "70.5 million emails, alerts and notifications" to customers in 2015 alone and that number will only increase going forward, SCE's concern regarding violations is well-founded.[657]

ORA may be correct that SCE has overstated the avoided costs to a small degree since SCE has the collective guidance of numerous CANSPAM and TCPA lawsuits to help it avoid violations in the future, but is unlikely that would be enough to make costs outweigh benefits here. Indeed, SCE notes that it could reduce avoided costs "to $32M over the five-year period and still show a positive benefit-to-cost ratio."[658] As such, ORA did not properly evaluate the benefit-to-cost ratio and the Digital Experience Project should not be rejected as a result of that evaluation.

The second issue involves SCE's failure to include additional capital costs in its benefit-cost analysis. "ORA states that SCE does not estimate any additional capital cost for IT refreshes or to maintain vendor support after four or

[655] *Id*. at 49.
[656] SCE-05, Vol. 2, Pt. 1 at 144 and fn. 145.
[657] *Id*. at 144.
[658] SCE-21 at 56.

five years. SCE agrees this omission was in error."[659] In order to correct this omission, SCE recalculated the benefit-cost analysis by adopting the Commission's 2012 GRC approach that "did not consider capital additions in the attrition years. This approach removes the SCE.com/CRM sub-project initial cost ($38.7 million) and associated benefits from the cost-benefit analysis. The project schedule does not begin until 2016, which is beyond the current rate case Test Year. By removing the SCE.com/CRM sub-project, the project timeline is reduced to five years, and no software package in the Digital Experience would mature beyond four years. Thus, the analysis requiring IT refresh expenditure or vendor support costs are appropriately excluded from the cost-benefit calculation."[660] ORA did not dispute or even discuss this change in the timeline.[661] Moreover, even if we reject SCE's timeline change, ORA already calculated the impact of including "additional total refresh cost" as reducing the benefit-cost ratio by 0.24.[662] In the absence of the avoided cost issue discussed previously, a 0.24 reduction of SCE's 1.96 ratio or its adjusted 1.70 ratio would fail to lower it sufficiently to conclude that costs outweigh benefits. Therefore, the failure to include additional capital costs in the analysis is not sufficient to reject this project.

Third, in its rebuttal, ORA objects to the inclusion of the Advanced Speech Recognition/Text to Speech Technologies and Customer Alerts and Notification sub-projects because "the Commission disallowed funding for [them] in the previous GRC decision as being unnecessary at that time."[663] Such a limited evaluation, however, relies on the circumstances for 2012 without examining the

[659] SCE-21 at 55, *see also* ORA-14 at 49.
[660] SCE-21 at 55-56.
[661] ORA Opening Brief at 253.
[662] ORA-14 at 49.
[663] *Id*.

circumstances for 2015. In fact, the 2012 GRC noted that the implementation of these two projects "may be more appropriate in 2013 or 2014."[664] According to SCE, implementation of the Alerts and Notification system "will promote accurate, timely, non-redundant communication to all SCE customers, government agencies, and business partners" and streamline compliance with "Do Not Contact" and "Do Not Call" requirements in Federal statutes.[665] This new system is needed because the current one "impedes SCE's ability to deliver timely, accurate, and non-redundant communication to customers."[666] Similarly, Advanced Speech Recognition (ASR) capability "is an industry standard for telephony self-service technology. SCE must invest in ASR to meet customer expectations now and in the future. PG&E, San Diego Gas & Electric, and Southern California Gas Company have all confirmed their use or pending deployment of ASR."[667] As such, given current industry standards and the need to avoid redundancy, funding for these programs should be allowed.

ORA's objections to SCE's benefit-cost analysis do not persuade the Commission the Digital Experience Program is fundamentally flawed. Likewise, ORA's rejection of the ASR/Text to Speech Technologies and Customer Alerts and Notification projects do not persuade the Commission that those components of the Program are unnecessary. More broadly, need is still an issue, just as it was for similar programs in 2012. While the Commission rejected those programs because it determined that SCE's existing systems were sufficient in 2012,[668] SCE has demonstrated that there is a current need for new systems based on the increasing growth of digital usage and changes in customer service

[664] D.12-11.051 at 369.
[665] SCE-05, Vol. 2, Pt. 1 at 134-135.
[666] *Id*.
[667] *Id*. at 131.
[668] D.12-11-051 at 369.

expectations for expanded support, personalized energy management, and streamlining information.[669] Moreover, ORA has not objected to any of the components of the Digital Experience Program based on need, instead focusing on the accuracy of the benefit-cost analysis. Therefore, we adopt SCE's Digital Experience Project forecast requests of $8.44 million for 2014 and $22.3 million for 2015.

9.3.3.5. Generation Management System (GMS)

The GMS project is designed to upgrade SCE's existing GMS to current vendor software versions, increase the capacity for telemetry connections to renewable generators, and lower future costs for the configuration of each generator connection.[670] SCE originally requested $1.5 million for 2013 and $0.194 million for 2014, however it spent only $0.891 million in 2013 due to delays in the contracting process pushing back the project start date.[671] Since the delays did not reduce the overall cost of the project but merely shifted its timeframe, SCE adjusted its 2014 forecast to account for the remaining $0.803 million of the total $1.5 million project budget. As discussed previously, an underspend in a prior recorded year resulting in an increase in the subsequent year's forecast by the amount underspent is neither automatic nor assumed – the increase requires justification to protect the ratepayers from unnecessary spending. Here, SCE's increase is justified by the project's delay and budget continuity. Since ORA "does not oppose SCE's request"[672] and the increased spending is justified, SCE's 2014 forecast is adopted.

[669] SCE-04, Vol. 2, Table VIII-66 and at 128-130.
[670] SCE-21 at 63.
[671] *Id*. at 63-64.
[672] ORA-14 at 57.

10. Human Resources, Benefits and Other Compensation

This chapter discusses the costs of hiring, retaining, and managing SCE's workforce. Although this includes the administrative costs of the human resources function, the majority of the costs represent the costs of compensation for SCE employees across many departments.

In each rate case, SCE and ORA jointly manage a TCS to analyze the total compensation of SCE employees relative to industry peers. In this case, Aon Hewitt prepared the TCS. The TCS concludes that SCE's overall compensation is 5% below market; the study has a 5% margin of error.[673] TURN questions the use of a peer group survey, such as the TCS, due to "bias" and notes that spot bonuses are not included in the TCS.[674]

One disputed issue is the role of rate recovery for incentive compensation. SCE argues that cost of service ratemaking principles require that if total compensation is at market levels, the total amount should be allowed. SCE further argues that it is inappropriate to consider whether ratepayers or shareholders are the primary beneficiary of variable incentive pay. SCE cites a number of precedents, both by this Commission and other venues, in support of its analysis, and quickly discards several recent Commission decisions concluding that none "withstands scrutiny."[675] We disagree. None of the precedents cited approvingly by SCE directly address the distinction between ratepayer and shareholder benefits. In our view, as evidenced by our recent precedents, this distinction is a key point in terms of incentive compensation. We agree with SCE that there are many examples of issues where shareholder and ratepayer benefits are aligned, including, for example, attracting, retaining, and

[673] SCE-6V2P2.
[674] TURN OB at 137-138.
[675] SCE-06V2P1 at 7-15.

motivating high quality employees. We also agree with SCE that not all utility transactions have a "winner" and a "loser." On the other hand, we observe that SCE's implication that past decisions have inferred otherwise (i.e., that "many, if not every, transactions" have a winner and loser) is a transparently self-serving strawman argument not supported by the text of those decisions. We caution SCE against employing such logical fallacies and suggest that SCE seek to manage its business to minimize the number of transactions which create a "loser" at all. We prefer a model where ratepayers, shareholders, and the community generally are all "winners" to the greatest extent possible. Further, we acknowledge that incentive pay programs can focus employee attention toward achieving goals that align with ratepayer interests. However, the interests of shareholders are only our concern to the extent that they align with ratepayer interests. Implicit in cost of service ratemaking is the concept that not all costs are reasonable costs of service: some costs may be unreasonable due to the magnitude of costs; other costs may be inadequately related to providing utility service to ratepayers. To the extent an incentive program (or any other cost) is designed to further objectives other than providing safe and reliable service at just and reasonable rates, the costs of that incentive program are not a reasonable cost of service, even if total compensation (including incentives) is at market. This is not unique to incentive compensation; if SCE pays an employee a salary to further objectives other than providing safe and reliable service at just and reasonable rates, that salary is not a reasonable cost of service, regardless of the level of total compensation. SCE bears the burden of proving that the costs of an incentive program are a reasonable cost of service. To the extent that SCE fails to meet this burden, ratepayers should not pay the costs. Such a finding in no

way bars SCE's shareholders from funding such an incentive program. This is consistent with cost of service principles.

In its comments on the Proposed Decision, SCE ignores much of the discussion above and attempts to suggest that this guidance is constraining SCE's discretion and that the "essential directive" is toward increased base pay and reduced incentive compensation.[676] We reject SCE's analysis, and highlight one alternative option for SCE management: target incentive compensation to achieve ratepayer benefits. This does not mean that shareholders cannot benefit from the incentives created, but simply that the metrics used to award incentive compensation should be designed explicitly to advance ratepayer interests.

10.1. Human Resources (HR) Department Expenses

SCE requests a total of $40.317 million in O&M for HR Department Expenses, excluding executive compensation, discussed below. These expenses are in FERC accounts 920/921, 923, and 926. SCE uses a combination of LRY and five-year recorded averages for the labor and non-labor components of these accounts, along with OpX adjustments and certain reductions related to SONGS.[677]

No party disputes the basics of the forecast, but ORA proposes an additional SONGS related reduction of $0.990 million to Accounts 920/921. ORA's reduction is based on removing 15 SONGS employees that charged to HR during 2012.[678]

In rebuttal, SCE explains that the 11 positions in dispute were temporarily dedicated to SONGS during 2012 due to the outage and were reassigned to support other groups within SCE. SCE notes that the scoping memo in this

[676] SCE Opening Comments at 7-8.
[677] SCE-6V1 at 46-50; SCE-6V1R at 9.
[678] ORA-16 at 10-12; ORA 16-A-R-2 at 4.

proceeding directed SCE to remove SONGS costs from its forecast, and claims it complied with this directive.[679]

SCE's rebuttal does not fully address the data presented by ORA, which shows that the number of SONGS HR employees peaked at 17 in 2011 and has been higher than the four positions removed by SCE from 2008 to 2012.[680] Nevertheless, we understand SCE's point that HR employees move between different parts of the company from time to time. Since SCE has failed to account for the full number of SONGS HR employees in the recorded data, we adopt one third of ORA's proposed reduction. We reduce SCE's forecast for HR department labor expenses in Accounts 920/921 by $0.330 million; other portions of SCE's HR department expenses are approved.

10.1.1. Executive Officer Expenses

SCE requests $21.022 million for executive cash compensation (including the Executive Incentive Compensation Plan [EIC], but not long term incentives) in FERC Accounts 920/921 and 923. SCE bases its forecast on five-year averages for Account 920/921 and a four-year average for Account 923. SCE's forecast includes a number of officers of Edison International (EIX) and officers shared between EIX and SCE.[681]

ORA accepts SCE's forecast and methods, but proposes that shareholders fund 91.25% of the EIC. ORA's primary rationale is that SCE did not demonstrate how executive incentives benefit ratepayers, beyond stating that ratepayers benefit from a focus on public safety, customer satisfaction, and other factors. Instead, ORA argues, the EIC is tied to financial performance and shareholder benefits. ORA uses information from EIX's Joint Proxy Statement,

[679] SCE-22 at 2.
[680] ORA-16 at 11.
[681] SCE-6V1 at 51-60.

and analysis of how specific goals do or do not benefit ratepayers to calculate its proposed 8.75% ratepayer contribution to EIC. In support of its proposal, ORA notes that the TCS found that SCE executive compensation is 9.5% over-market and that in D.12-11-051 we authorized 50% of EIC costs to be paid by ratepayers. ORA's recommendation leads to a $6.251 million reduction to SCE's forecast for labor in Account 920; ORA does not contest other elements of SCE's forecast.[682]

TURN argues that 60% of EIC goals are tied to financial performance (40%) or lobbying (20%) based on TURN's analysis of SCE's joint proxy statement.[683]

In rebuttal, SCE makes several responses to ORA. SCE argues that ORA misuses the TCS, claiming it is inappropriate to look at any individual job category and showing that the TCS evaluation of executive compensation has fluctuated in recent GRCs. SCE claims that reducing EIC to the level proposed by ORA would harm SCE's ability to attract and retain qualified executives by reducing total compensation to 24% below market. SCE also suggests that it is inappropriate micromanagement for the Commission to set specific components of compensation, and that if the Commission does so, SCE would likely shift compensation to base pay. SCE claims that financial performance of the utility benefits ratepayers through lower borrowing costs. Finally, SCE claims that no party has shown its costs are unreasonable or imprudent, and that disallowing them would be confiscatory and counter to cost of service ratemaking.[684]

In D.12-11-051,[685] we allowed rate recovery of 50% of SCE's forecast for EIC, noting that this was based on what was reasonable to charge to ratepayers. In this case, ORA and TURN have put forward analysis indicating that the EIC awards are largely given based on shareholder benefits. Although SCE claims

[682] ORA-16 at 16-23.
[683] TURN-12 at 18.
[684] SCE-22 at 4-11.
[685] At 450.

that the Joint Proxy Statement was written for a shareholder audience,[686] it does not provide any credible alternative reading of the awards criteria to support its implication that EIC awards are targeted to achieve ratepayer benefits. SCE's comments that some of the awards are based on benefits shared by ratepayers and shareholders are very limited examples. We agree with SCE that financial performance may benefit ratepayers, however the ratepayer benefit is much less direct than the shareholder benefit. Further, in some instances, financial performance may be achieved at the detriment of ratepayers. Accordingly, we adopt 40% of SCE's EIC forecast for rate recovery and approve the non-EIC portions of SCE's executive compensation request. If SCE seeks rate recovery of higher portions of the EIC in its next GRC, it should provide substantially more evidence that the EIC awards incent executives to achieve ratepayer benefits.

10.2. Short Term Incentive Program (STIP)

SCE's STIP consists of: (a) Results Sharing (RS) program; (b) Management Incentive Program (MIP); and (c) Non-Officer Executive Incentive Compensation Plan (NOEIP). In some instances, the terms STIP and RS are used synonymously in testimony. These programs (together with EIC, above) provide an opportunity for all employees to earn a bonus linked to individual, OU, or Company performance. SCE describes an annual cycle for setting OU and Company goals and evaluating performance. SCE claims that the company goals "are overwhelmingly tied to matters benefiting ratepayers." SCE's total forecast is $143 million in FERC Accounts 500, 588, 905, and 920/921, down 18% from 2012 recorded. SCE's forecast is based on the 2012 ratio of STIP costs to total non-capital labor costs, applied to the 2015 labor forecast.[687]

[686] SCE-22 at 9.
[687] SCE-6V2P1 and SCE-6V2P1R at 1, 16-22.

ORA proposes using a 2008-2013 average of the ratio of STIP to labor, instead of SCE's use of 2012 recorded, which ORA notes is the highest year in that period. ORA calculates this as 12.08% compared to SCE's 15.97%. Using ORA's labor forecast, ORA calculates a STIP forecast of $97.543 million. Further, ORA proposes to "allocate" different fractions of STIP costs to ratepayers (0% for NOEIP, 50% for MIP, 50% for RS non-union employees, and 75% for union employees in RS), averaging to 45.5% to shareholders and the remaining 54.5% to ratepayers. ORA claims its proposal recognizes benefits to ratepayers and shareholders. ORA further argues that the STIP gives disproportionate awards to managers and executives relative to rank and file employees. In ORA's view, NOIEP should be shareholder funded because it is driven by financial performance, PG&E did not seek rate recovery of its analogous program in its most recent GRC, and SCE executives are above market by more than the margin of error (5%) in the TCS. For MIP and non-union employees in RS, ORA's analysis of the payout criteria suggests that both shareholders and ratepayers benefit, and ORA proposes a 50-50 split. ORA considers union contracts and the reduced flexibility of management in its proposal for 75% ratepayer funding of RS for union employees. In summary, ORA proposes ratepayer funding of $53.155 million.[688]

TURN proposes a variety of reductions to SCE's STIP forecast. First, TURN recommends retaining the 10.94% factor for calculating the STIP forecast adopted in D.12-11-051, noting that SCE proposes a 46% increase in this ratio and that SCE's 2012 recorded payments were 127% of target. Second, TURN proposes that goals related to lobbying should not be eligible for ratepayer funded STIP payouts, citing both of SCE's most recent GRC decisions. Using

[688] ORA-16 and ORA-16AR2 at 24-36.

2014 goals, TURN enumerates several STIP goals that it finds related to lobbying, not necessarily in the interest of ratepayers. TURN calculates reductions of 14% for External Relations and 37% for Government Affairs. Third, TURN proposes that ratepayers fund half or none of O&M savings goals depending on whether ratepayers receive all or half of OpX savings addressed below in Section 25. TURN argues that benefits for O&M savings are "at best" shared between ratepayers and shareholders, depending on whether efficiency drives the savings. Fourth, TURN calculates that 40% of NOEIP are based on financial performance and an additional 20% is based on strategic initiatives, including lobbying, and correspondingly recommends that ratepayers fund 40% of NOEIP.[689] TURN agrees with ORA that STIP disproportionately rewards managers.[690]

SBUA recommends that "quality of service to small businesses be included" in STIP, but does not elaborate.[691]

In rebuttal to ORA and TURN, SCE makes several arguments. SCE claims that ORA's six-year average method is flawed for two reasons. First, it relies on unadjusted 2013 data and incorrectly addresses inflation. Accounting for these errors, SCE calculates a six-year average of 12.11%. Second, SCE alleges that the recorded data shows a clear upward trend, and that therefore, LRY is appropriate. SCE argues that TURN's proposal to use a 10.94% ratio inappropriately "assumes Company and OU performance remains static and eliminates any incentive to achieve better than target performance." Further, SCE suggests that TURN and ORA do not consider the TCS's conclusion that total compensation is 5% below market and repeats its cost of service arguments

[689] TURN-12 at 2-20.
[690] TURN OB at 140.
[691] SBUA-1 at 23.

discussed above, in favor of 100% rate recovery. SCE claims that none of the employees covered by NOEIP are included in the "Executive" category of TCS, and that therefore ORA misrepresents the TCS. SCE claims that its testimony shows ratepayer benefits from STIP goals.[692]

In recent GRCs, we have adopted reductions to short term incentives to account for payouts that are driven by shareholder benefits rather than ratepayer benefits. For example, in D.12-11-051, we allowed rate recovery of 90% of STIP and in D.14-08-032 excluded certain categories. As TURN and ORA demonstrate here, significant portions of the payout criteria are directly related to shareholder benefits such as achieving decisions in CPUC proceedings (GRC, cost of capital) with certain outcomes and achieving specified public policy objectives that may or may not provide secondary benefits to ratepayers. As discussed above, SCE bears the burden of proving that incentive programs are a reasonable cost of service, and has not demonstrated that costs related to these criteria are reasonable. Moreover, we agree with TURN and ORA that the proposed significant increase in the ratio of STIP payments to total labor is not adequately justified, especially given that STIP payments in 2012, on which SCE bases its proposal, were 27% above target. We find SCE's argument that an historical average of this ratio is inappropriate to be unpersuasive – we disagree that 2008-2013 shows a clear trend. However, we do place weight on the results of the TCS and decline to adopt the deep cuts proposed by TURN and ORA. To calculate STIP forecast, we apply the 12.11% ratio of STIP to total labor, as calculated by SCE based on ORA's proposed six-year average, to SCE's total labor forecast, then reduce that amount by 10% to account for STIP payout criteria that are not appropriate to charge to ratepayers. This forecast would be

[692] SCE-22 at 14-25.

approximately $98 million using SCE's labor forecast, but we calculate the actual forecast using adopted labor values.

10.3. Long Term Incentives (LTI)

SCE forecasts $18.18 million in LTI, noting that LTI is an important (24-53%) component of total direct compensation for its executives, and that this is common practice among large companies. LTI is recorded in FERC Account 920. SCE describes the two criteria for granting LTI stock options; both are solely based on EIX financial performance. SCE argues that LTI helps to retain employees and motivate them to take actions in the long-term best interest of customers. SCE repeats its cost of service arguments described above.[693]

ORA, TURN, and SBUA all oppose rate recovery of LTI on the grounds that SCE has not clearly shown benefit to ratepayers. For example, SBUA argues that LTI "do not have a direct relationship to utility services."[694]

In recent decisions, we have held that LTI is not recoverable from ratepayers because LTI does not align executives' interests with ratepayer interests.[695] SCE's arguments to the contrary are vague, limited, and unpersuasive. SCE has not demonstrated that LTI furthers the provision of safe and reliable service at just and reasonable rates. We continue our consistent practice and reject rate recovery of SCE's LTI program.

10.4. Recognition Programs

SCE has two recognition programs: Spot bonuses and Awards to Celebrate Excellence (ACE). Spot bonuses are cash awards for achievements such as promoting safety or leading programs that improve efficiency. ACE is a points-based program for participants in safety efforts. SCE does not provide a

[693] SCE-6V2P1 at 23-28.
[694] SBUA OB at 12, ORA 16 at 38-39, and TURN OB at 145-148.
[695] D.12-11-051 at 451-452; D.13-05-010 at 882-884.

specific forecast for these programs; instead they are included in the labor component of OU forecasts.[696]

ORA opposes these programs, finding the forecast unclear and claiming that SCE has not established ratepayer value. ORA notes that for ACE, SCE's data request responses suggest that costs are recorded as non-labor. Further, ORA argues that these programs are inappropriately duplicative of the STIP discussed above.[697]

In rebuttal, SCE emphasizes the safety connection of the ACE program and differentiates Spot bonuses from STIP based on timing. SCE argues that, therefore, these programs provide real and unique ratepayer value at a reasonable cost.[698]

We agree with SCE that the types of behaviors (e.g., a focus on safety) that these programs reward do further the provision of safe and reliable service at just and reasonable rates. Further, we agree that the costs appear reasonable relative to the benefits. However, we share ORA's concern (noted previously in D.12-11-051[699]) that SCE's forecast is not transparent. Therefore, we consider these programs in context of the individual OU budgets, rather than making any specific authorization or disallowance here. Further, we direct SCE to present a clear and coordinated showing on its forecast for these recognition programs in its next GRC direct testimony.

10.5. Pension and Benefits Programs (Account 926)

SCE forecasts $384.662 million for benefits including: pension, 401(k), health care, disability, group life insurance, and executive benefit plans. All costs are recorded in FERC Account 926, with the large majority recorded in the

[696] SCE-6V2P1 at 29-30.
[697] ORA-16 at 41-47.
[698] SCE-22 at 31-35.
[699] At 459-460.

"Other" cost category.[700] The table below summarizes our adopted forecast (millions of 2012$). We note that the numbers presented in the table assume that SCE's labor forecast is adopted, but in fact the actual adopted labor forecast contains numerous differences relative to SCE's forecast. The actual adopted pension and benefit figures (not shown here) are calculated in the RO model, using the same ratio of pensions or benefits to labor expense as the illustrative adopted numbers shown here, applied to the adopted labor forecast.

	SCE	Illustrative Adopted
Pensions	88.326	88.326
Post-Retirement Benefits Other than Pensions	44.573	44.573
Other Benefits	251.763	243.130
Total	384.662	376.029

10.5.1. Pensions

In the update phase, SCE reduced its pension forecast to $88.326 in response to a change in law and updated actuarial information. SCE cites this change as support for the importance of two-way balancing account treatment.[701] This value is considerably lower than ORA's prior forecast of $155.077 million. ORA also proposes a change to a one-way balancing account, or alternatively a 90-10 sharing mechanism for ratepayer-shareholder responsibility for any actual pension contributions above the authorized amount. ORA argues that these approaches provide just and reasonable "checks and balances" for cost control in this area.[702]

In D.12-11-051, we directed SCE to review its pension practices. In response, SCE includes a comparison of its pension practices to those of other CA utilities (public and investor owned) and state employees. Generally, this review

[700] SCE-6V2P1 and SCE-6V2P1R at 31-32.
[701] SCE-73 at 21-22.
[702] ORA-17 and ORA-17A at 3-7.

concludes that employees receive comparable total benefits for comparable total contributions, even though there are relative differences between defined-benefit and defined-contribution portions.[703]

SCE contends that its pension contributions are set by law and actuarial standards, and are not under its control.[704]

We adopt SCE's updated forecast and proposed balancing account treatment. Minimum pension contributions are not controlled by SCE and are appropriate for balancing account treatment.

10.5.2. Post-Retirement Benefits Other than Pensions (PBOPs)

SCE offers PBOPs. These benefits include post-retirement medical, dental, vision, Medicare Part B premium reimbursement, Employee Assistance Program, and term life insurance. SCE describes significant changes to reduce costs for PBOPs over time. SCE has established certain trust funds to make tax deductible contributions to finance PBOP costs. PBOP costs are recovered via the existing two-way PBOP Balancing Account. In most recent years, PBOP costs have been lower than authorized, and excess contributions have been periodically returned to customers. Aon Hewitt, SCE's PBOP actuary, estimates a 2015-2017 average PBOP costs of $44.156 million, down from $53.378 authorized in the 2012 GRC. This estimate includes workforce reductions through May 2013. SCE also requests $0.42 million for PBOP actuarial fees. SCE's total PBOP forecast is $44.573 million.[705]

ORA recommends a total PBOP forecast of $42.017 million based on an updated actuarial calculation.[706] SCE observes that ORA's updated 2014-2015 forecast is actually higher than the 2015 estimate that SCE used, as a component

[703] SCE-6V2P1 at 32-51 and SCE-73 at 21-22.
[704] SCE-22 at 40-45.
[705] SCE-6V2P1 at 80-90.
[706] ORA-17 at 7.

of its 2015-2017 average. SCE argues that the three-year average approach should be continued and that it is inappropriate to recalculate the forecast every time new information is available. We agree with SCE and adopt SCE's forecast.

10.5.3. Other Benefits

This section addresses several other benefits provided by SCE, including: 401(k) savings plans; medical, dental, and vision programs; disability; life insurance; and executive benefits. SCE's proposals are briefly summarized below:

- 401(k) – SCE forecasts $64.940 million in costs for matching employee contributions (up to 6% of each employee's salary). SCE's forecast is based on the ratio of 2012 recorded 401(k) costs to 2012 recorded labor costs, escalated by the labor escalation factor discussed in Section 18 below, and applied to SCE's total 2015 labor cost forecast.
- Medical – SCE forecasts $131.110 million, including a variety of health insurance plans, preventive health accounts, and employee assistance program for short-term counseling services. The forecast is based on number of eligible employees and per-eligible-employee costs, escalated by an annual trend rate of 5.4% in 2013 and 8% for 2014 and 2015. This trend rate was produced by SCE after "review of Edison's actual medical plan trends, the trend rates provided by the administrators of SCE's medical plans, as well as outside consulting firm projections of trend, and taking into account the significant pressures on medical plan costs . . . ".[707] SCE's medical plan administrators provided estimates of escalation rates ranging from 9.8% to 11% in 2014 and 2015. SCE discusses the cost increases expected by other employers and concludes that its forecast trend rate is reasonable. SCE cites recent federal health care reform legislation and increasing utilization of health care services as examples of factors leading to increased cost per-eligible-employee.

[707] SCE-6V2P1 at 73.

- Dental – SCE forecasts $14.777 million based on the number of eligible employees times per-eligible-employee cost forecast, increased based on trends provided by the dental plan providers.
- Vision – SCE forecasts $3.122 million based on the same method as dental and medical, with per-eligible-employee cost escalated by 2% per year, as projected by the plan provider.
- Disability – SCE forecasts $14.533 million based on the same method as dental and medical, with per-eligible-employee costs based on 2012 costs, escalated by the labor escalation rate as discussed in Section 18.
- Group Life Insurance – SCE forecasts $1.252 million based on the same method as dental and medical, with per-eligible-employee costs based on 2012 costs, unescalated.
- Miscellaneous Benefits – SCE forecasts $4.763 million based on the same method as dental and medical, with per-eligible-employee costs based on 2012 costs, escalated by the non-labor escalation rate as discussed in Section 18. This benefit is primarily a 25% discount on electric service for employees living in SCE's service territory.
- Executive Benefits - SCE forecasts $17.266 million based on an annual actuarial valuation calculated by Aon Hewitt, considering factors including number and age of executives, bonuses, and expected mortality. Executive benefit costs are net of the SCE's pension system and 40% of social security benefits.[708]

ORA rejects SCE's basic approach and contends that 2013 data should be used for the forecast. ORA bases its primary proposed adjustment to the forecast on comparing SCE's 2013 forecast to SCE's 2013 FERC Form 1 data, adjusting for capitalization. On this basis, ORA reduces SCE's forecast by 15.1%. ORA makes further reductions for medical and disability escalation rates and using its own total labor forecast. ORA proposes to disallow entirely the executive benefits.

[708] SCE-6V2P1 and SCE-6V2P1R.

ORA's total medical forecast is $96.997 million based on the above factors. ORA uses the Berkeley Healthcare Forum for its medical escalation rate of 6.6% per year, noting that this is a California-specific forecast. ORA also notes a variety of lower, national forecasts of medical inflation, including Global Insight which is used by both SCE and ORA to escalate other rates in this GRC.

For disability, ORA forecasts $11.132 million by using SCE's proposed labor escalation rate, in addition to the 15.1% reduction and using ORA's forecast for total labor.

ORA proposes to disallow the executive benefits entirely, arguing that costs and benefits beyond those of other employees should be funded by shareholders. ORA claims that because these benefits are above those specified in the Internal Revenue Code (section 401(a)), these benefits are not appropriate for rate recovery. ORA cites several decisions from other jurisdictions in support of its view, and notes that in 2009 and 2012, we reduced SCE's recovery of these benefits by 50%. ORA also specifically objects to supplemental survivor, disability, and severance benefits that are afforded to executives, but not other employees.[709]

SCE objects to ORA's 15.1% reduction, claiming that ORA inappropriately relies on preliminary, unadjusted data from FERC Form 1. SCE claims to have identified two adjustments, totaling $28 million in a "cursory" review and that applying these adjustments would reduce ORA's 15.1% to 5%. SCE further claims that it is inappropriate and mathematically flawed for ORA to apply the reduction to individual programs. SCE also suggests that the approved labor forecast should be used for all benefit calculations. For certain benefits, SCE also makes specific arguments, as discussed below.

[709] ORA-17 at 8-16.

SCE finds no basis for ORA's proposed reduction to the 401(k) program in ORA-17, and recommends rejecting this proposal.

SCE rejects ORA's use of the Berkeley Healthcare Forum's 6.6% medical escalation rate. After reviewing the report, SCE concludes that a key component of the 6.6% forecast is "simply an educated guess." Further, SCE argues that certain other sources discussed by ORA for medical escalation are inapplicable for various reasons.

SCE believes that ORA's calculation of dental benefits inadvertently relied on an outdated per-eligible-employee cost.

For disability, SCE claims that ORA's proposed reductions are based on using the general labor escalation factor are already included in SCE's testimony and that ORA inadvertently used an outdated per-eligible-employee cost.
SCE claims that the executive benefits program promotes retention of qualified executives, is market competitive (citing the TCS), and should be recovered in rates. SCE cites counterexamples to ORA's citations in other jurisdictions.[710]

In its brief, ORA notes that the FERC Form 1 data it relied on was labeled as "2013 Recorded Adjusted" and that SCE would later provide an update, and that no such update was provided before ORA submitted its testimony. ORA also points out that SCE's witness could not describe whether any additional adjustments were found beyond those discussed in SCE's rebuttal. Further, ORA notes that SCE's rebuttal states that the FERC Form 1 data includes other expenses, not discussed in this section, suggesting that the 15.1% calculated by ORA may be an underestimate.[711]

With the exception of Executive Benefits, we adopt SCE's forecast. SCE's basic approach of calculating per-eligible-employee costs, escalating those costs,

[710] SCE-22
[711] ORA OB at 290-291.

and multiplying by the number of eligible employees is reasonable. While we are sympathetic to ORA's desire to use 2013 data, the differences between the recorded and forecasted data are unclear. Further, the continued use of the Medical Programs Balancing Account ensures that customers will only pay the actual cost of the medical, dental, and vision benefits. However, we do remind SCE that it bears the burden of proof in its GRCs, and that it must be careful to accurately label data (e.g., adjusted or unadjusted) in its data request responses and to update responses when better information is available. For medical escalation, we give significant weight to SCE's reference to escalation rates provided by its plan administrators, and find this preferable to relying on a broader public study as proposed by ORA.

For Executive Benefits, we follow the precedent of the 2009 and 2012 GRCs,[712] and allow 50% rate recovery of SCE's forecast. These Executive Benefits are, in part, based on bonuses received by the executives. As discussed above, these bonuses may not be appropriate for rate recovery. Accordingly, benefits based on those bonuses are also not appropriate.

The adopted forecast is (millions of 2012$):[713]

	SCE	ORA	Illustrative Adopted
Medical Programs	131.110	96.998	131.110
401(k) Savings Plan	64.940	58.367	64.940
Dental Plans	14.777	10.669	14.777
Vision Service Plan	3.122	2.381	3.122
Disability Program	14.533	11.132	14.533
Group Life	1.252	0.952	1.252
Miscellaneous Benefits	4.763	3.616	4.763
Executive Benefits	17.266	0.000	8.633

[712] D.12-11-051 at 476-477.

[713] The employee benefits shown in the table are dependent on the number of employees based on labor expenses approved by this decision. The adopted expenses shown in the table are illustrative and may not match the final amounts.

Total	251.763	184.115	243.130

11. Safety, Security & Compliance (SS&C)

SS&C operating unit was formed in 2012 of existing departments. The group focuses on safety of workers and the public, security of people and infrastructure, preparation to respond to events, and compliance with law and regulation. SCE forecasts an increase in O&M costs relative to 2012 recorded, driven by a need to increase security and secure more locations according to NERC CIP. SCE also states that it needs to improve its resiliency to respond to major disruptions (e.g., earthquakes). Capital expenditures are driven by the same factors in addition to marine mitigation programs related to SONGS (See Section 11.2.5 below). SCE states that safety is a paramount objective of the company, and all four departments of SS&C (Ethics and Compliance; Corporate Environmental, Health, and Safety; Corporate Security; and Business Resiliency) contribute to this goal. Additionally, SS&C contributes to reliability and sustainability of SCE's electric service.[714]

[714] SCE-7V1.

Our adopted O&M forecast is summarized below (millions of 2012$).

	Account(s)	SCE	Adopted
Ethics and Compliance	920/921, 923	$ 8.120	$ 8.120
CEHS Management and Environmental Services	920/921	$ 4.833	$ 4.833
CEHS - Marine Mitigation	920/921	$ -	$ 3.702
Transmission Environmental Services	566.250	$ 5.174	$ 5.174
Distribution Environmental Services	582.250	$ 2.289	$ 2.289
Health and Safety	925	$ 3.785	$ 3.785
Outside Consulting	923	$ 0.475	$ 0.475
Corporate Security and Business Resiliency	920/921, 923	$ 44.368	$ 44.368
Total		$ 69.044	$ 72.746

Our adopted capital forecast is summarized below (millions of nominal$).

	SCE		Adopted	
	2014	2015	2014	2015
Corporate Security & Business Resiliency	$60.623	$20.369	$60.623	$20.369
SONGS Marine Mitigation	$ -	$24.693	$ -	$ -
Total	$60.623	$45.062	$60.623	$20.369

11.1. Ethics and Compliance (Accounts 920/921, 923)

This department was formed in 2005. SCE forecasts $8.120 million in O&M for Ethics and Compliance, based on 2012 recorded. In addition to the O&M request, two IT capital projects, discussed above in Section 9.3, are important to this department's work. SCE details the work of the department and provides data in response to certain requirements in D.12-11-051.[715]

ORA proposes a 10% reduction on the basis that shareholders should pay a portion of the costs. ORA contends that many of the functions within the Ethics and Compliance department benefit shareholders via reduced risk of lawsuits,

[715] SCE-7V2.

for example. Moreover, ORA questions the efficacy of the department and believes that there are inconsistencies in SCE's showing. For instance, ORA asserts that there are fewer staff in the Drawings Management group in 2012 than in 2009, but increases in staffing are cited by SCE as a basis for its request.[716]

TURN proposes certain adjustments that are addressed in Section 28.1 below.[717]

SCE rebuts ORA's attack on the efficacy of the department by showing that much of the information relied on by ORA predates significant improvements following the 2012 GRC. Further, SCE argues that there is no basis for ORA's proposal to allocate 10% of costs to shareholders, that there is no precedent for such an allocation.[718]

In its brief, ORA discusses the impact of federal legislation (Sarbanes Oxley Act) in support of its position that compliance benefits shareholders more than ratepayers. Further, ORA argues that SCE provided no recent information supporting the success of Ethics and Compliance, and that SCE's criticism of ORA's sources is unfair.[719]

Notwithstanding ORA's arguments, we agree with SCE that the forecast O&M costs of the Ethics and Compliance department are reasonable. Ratepayers benefit from a strong culture of ethics and compliance, and SCE has demonstrated success in making improvements in the department. SCE's forecast is adopted.

[716] ORA-18 at 7-12.
[717] TURN-5 at 121-122.
[718] SCE-23 at 4-5.
[719] ORA OB at 303-305.

11.2. Corporate Environmental, Health, and Safety (CEHS) (Accounts 566.250, 582.250, 920/921, 923, and 925)

CEHS is responsible for two basic areas: environmental services, and health and safety. CEHS develops and manages programs across SCE in these areas, including compliance with various statutory and regulatory requirements. CEHS works with many OUs, and costs for projects specific to an OU unit are charged back to the OU.

SCE contends that an increase above 2012 recorded-adjusted O&M expenses is needed because 2012 was anomalous. CEHS also forecasts costs for SONGS marine mitigation. Finally, CEHS presents certain environmental services costs for transmission and distribution, but these costs are accounted for in Section 7.10.4 above.[720]

11.2.1. CEHS Management and Environmental Services (Account 920/921)

This category includes costs not tied to a specific capital project or OU-specific project such as: coordination, environmental siting, permitting, reporting, development and implementation of company-wide management systems and controls, compliance assurance, and training. SCE finds "significant fluctuation" during 2008-2012 in recorded costs. SCE forecasts labor and non-labor costs based on five-year averages.[721]

ORA accepts SCE's forecast, but recommends an additional incremental O&M expense associated with SONGS Marine Mitigation, discussed in Section 11.2.5 below.[722] SCE opposes ORA's recommendation, but also provides an alternative calculation of the impact of accepting ORA's recommendation.[723]

[720] SCE-7V3 at 1-2.
[721] SCE-7V3 at 3-8.
[722] ORA-18 at 14.
[723] SCE-23 at 7.

We adopt SCE's uncontested forecast plus $3.703 million (2012$) in expenses for SONGS Marine Mitigation, as describedbelow.

11.2.2. Environmental Services for Transmission and Distribution (Portion of Account 566.250 - Transmission and Entirety of Account 582.250 - Distribution)

CEHS performs these activities, but the costs record to FERC Accounts in T&D in Section 7.10.4 above. CEHS provides services including environmental program development, implementation and onsite mitigation for T&D projects.

SCE's costs have increased during 2008-2012 due to major transmission projects and implementation of the Compliance Management System (CMS). SCE explains that as projects are completed environmental costs, shift from capital to expense, particularly onsite mitigation.

SCE's transmission forecast for 2015 is based on 2012 recorded plus an estimate based on capital project completion. The incremental estimate is based on an average of SCE's forecasts for 2015-2017. SCE refers to draft Habitat Mitigation Plans, as available, to create the forecast.

SCE's distribution forecast is based on 2012 recorded. SCE notes it considers the work and costs stable, and does not anticipate changes.[724]

For transmission, ORA opposes most of SCE's incremental estimate, and instead proposes that SCE's 2013 forecast be adopted for the test year. ORA notes that this forecast is 111% more than SCE's 2012 recorded and asserts that SCE has not justified its requested increase relative to historic levels. ORA recommends we require SCE to provide more recorded cost detail on projects in the next GRC.[725] For distribution, ORA does not contest SCE's forecast.

[724] SCE-7V3 at 9-17.
[725] ORA-9 at 44-47.

SCE responds that it would be unreasonable to rely solely on historical data because costs are driven by the transmission projects that will be brought into service and begin on-site mitigation. SCE considered historical costs for the relevant activities, but also anticipated changes to the amount of work required. SCE notes that ORA provided no analysis for selecting SCE's 2013 forecast for 2015. SCE provides considerable details supporting its cost estimates related to transmission projects as attachments to its rebuttal. Further, SCE notes that we approved significant increases for these activities for PG&E, despite similar arguments from ORA.[726]

We find SCE's uncontested distribution forecast reasonable. For transmission, we find that SCE has justified its requested increase based on a credible analysis of work likely to be required due to new transmission projects. SCE's forecasts are reasonable and are adopted.

11.2.3. Health and Safety (Account 925)

Health and safety personnel provide expertise on industrial hygiene, electrical safety, confined space, and safety culture and work with OUs to implement standards. SCE shows improvement in injury rates 2008 to 2012. Recorded costs are stable, except for a periodic (every three years) Safety Culture Assessment, last done in 2011. Labor costs are based on 2012 recorded; non-labor costs use a three-year (2010-2012) average. SCE notes that the Safety Culture Assessment adds nearly $1 million to the base non-labor expense.[727]

ORA recommends a five-year recorded average for labor costs, noting "slight fluctuations" and a 25.3% increase from 2008 to 2012. ORA accepts SCE's non-labor forecast.[728]

[726] SCE-23 at 8-10
[727] SCE-7V3 at 18-22.
[728] ORA-18 at 17-18.

Citing D.04-07-022, SCE argues that ORA's proposal is inconsistent with our forecasting guidance. Further, SCE contends that cuts to safety labor would be inconsistent with our focus on safety.[729]

We agree with SCE that labor expenses have been stable and therefore SCE's forecast based on 2012 recorded is appropriate. SCE's non-labor forecast is uncontested. SCE's forecast for Health and Safety in Account 925 is reasonable and is adopted.

11.2.4. Outside Consulting Services (Account 923)

SCE forecasts this account based on a five-year average, noting significant annual variation. All expenses are non-labor.[730] ORA recommends using 2012 recorded, citing a downward trend in the last three years and claiming that SCE is not aware of specific projects that will require services.[731] SCE responds that this uncertainty is why the average is appropriate. SCE foresees cost increases based on increasing regulatory emphasis on safety.[732] SCE's forecast follows our guidance to use an average for accounts with high variability. SCE's forecast is reasonable and is adopted.

11.2.5. Marine Mitigation Projects

SONGS Marine Mitigation Projects are required by the Coastal Development permit (CDP) for SONGS. The projects are intended to mitigate impacts of SONGS operations on the marine environment. The projects include four components: reef, wetland, fish return system, and a fish hatchery program. The CDP requires these projects for "the full operating life of SONGS." The reef and wetland have not yet been accepted by the California Coast al Commission.

[729] SCE-23 at 11-12.
[730] SCE-7V3 at 23-24.
[731] ORA-18 at 17.
[732] SCE-23 at 12-13.

SCE states that, although the projects are complete, additional capital is required to maintain and improve the projects.

For the wetland, SCE began monitoring in 2012 and believes that some, but not all, standards will be met in 2012. SCE's forecast is based on its expectation for specific work to be completed.

For the reef, CCC scientists have completed 2009-2012 performance monitoring, indicating that seven of fourteen standards are met. SCE forecasts expenditures for oversight and monitoring as well as further construction.[733]

SCE removed 2013 and 2014 capital expenditures from its application due to approval of D.14-11-040.[734]

SDG&E owns a 20% interest in SONGS and is responsible for 20% of SONGS costs, including marine mitigation. SDG&E requests a revenue requirement consistent with 20% of the total marine mitigation costs approved plus contractual overheads added by SCE and will file an Advice Letter to implement this revenue requirement. SDG&E calculates its revenue requirement including its own overheads, taxes, and rate of return.[735]

ORA recommends that these costs be expensed rather than capitalized and that SCE attempt to amend the CDP to reflect a lesser environmental impact due to SONGS's retirement. Further, ORA recommends a 50/50 cost sharing recommendation to incent SCE to pursue these changes. ORA contends that SONGS is no longer used or useful and that circumstances have changed significantly since D.96-04-059. ORA proposes an increase to SCE's environmental services forecast (Account 920/921, Section 11.2.1 above) to

[733] SCE-7V3 at 25-30.
[734] SCE OB at 244 and SCE-73 at 20.
[735] SDGE-1 and SDGE-2.

implement its recommendation. Finally, ORA contends it is "unlikely" that SCE will largely complete reef construction in 2015.[736]

SCE rejects ORA's cost sharing proposal as baseless, noting that the mitigation requirements predate the shutdown and are written to continue even after SONGS is fully decommissioned. Further, SCE explains that it intends to file an amendment request for the CDP during Fall 2014 seeking a change that would potentially relieve SCE of an obligation to build additional reef. However, the result of this request is uncertain. SCE argues that an "added incentive" would not change its course of action. Finally, SCE argues that mitigation is a proper cost of service and that cost sharing constitutes an unjustified penalty.

SCE does not oppose expensing mitigation costs, as long as the full costs are included. SCE calculates a normalized O&M requirement of $7.867 million for reef construction and $1.989 million (2012$) for wetlands restoration.

Finally, SCE contends that ORA is wrong in its view that SCE will not be able to do major work on the reef in 2015 and presents an expected schedule.[737]

SDG&E expresses willingness to expense costs, but recommends that we leave the determination of which costs to expense to SDG&E and SCE.[738]

TURN recommends that we deny cost recovery of these costs in GRC rates for several reasons: CCC has not yet required the reef construction contemplated in SCE's forecast and TURN believes SCE should attempt to recover any costs through the decommissioning trust.

TURN considers the mitigation costs here largely indistinguishable from costs addressed in D.14-11-040. TURN argues that costs (other than reef

[736] ORA-18.
[737] SCE-23 at 14-17.
[738] SDG&E OB at 8-9.

construction) are "completed CWIP" as defined by that decision, and recommends that they be treated accordingly.

TURN recommends that we require SCE to file an application for reef construction costs in the event that CCC actually institutes such a requirement. Further, TURN submits that SCE's cost estimates for reef construction rely on prior estimates rather than recorded costs and an unsupported 4% escalation rate.

TURN recommends seeking an IRS letter ruling on use of the decommissioning trusts to fund marine mitigation, and argues that a prior letter ruling did not address this subject.

Finally, TURN supports ORA's proposal to expense any costs approved in this proceeding. TURN notes that, other than reef construction, the forecast costs all relate to supporting existing projects. Citing overspending on marine mitigation relative to past authorizations, TURN argues that expensing these costs creates a stronger disincentive to overspending.[739]

For reef construction, SCE claims that cost recovery through a separate application would be inefficient and that its forecast for reef expansion is reasonable. In response to TURN's comments, SCE presents a revised forecast incorporating TURN's proposed escalation rates and recorded cost data.

SCE argues that applying the ratemaking approach of the settlement adopted in D.14-11-040 to marine mitigation costs is inappropriate because that settlement does not address this subject.

SCE considers TURN's request for an IRS letter ruling to be an inefficient use of resources, noting that the existing IRS letter specifically categorizes

[739] TURN-1 at 14-24.

"environmental remediation for off-site locations" as nonqualified for trust funding.[740]

SDG&E also opposes ORA's and TURN's recommendations to reduce SCE's forecast or delay consideration of reef construction costs. SDG&E supports SCE's views that mitigation costs are not eligible decommissioning costs and should not be addressed similar to D.14-11-040.[741]

In its brief, TURN argues for a different interpretation of the IRS letter ruling, emphasizing that the IRS gives deference to local commissions to determine whether a cost is a decommissioning cost.

Further, TURN calculates a reef-maintenance (i.e., excluding construction) O&M forecast of $1.278 million.

TURN also rejects SCE's updated reef construction forecast, noting that it includes line items for "monitoring" and "site selection," for example, and is not limited to construction costs.

Moreover, TURN rejects SCE's schedule (showing reef completion in early 2016) as baseless and unrealistic in light of past experience.[742]

Rate recovery for costs up to 2014 have been resolved by D.14-11-040. We agree with ORA and TURN that it is appropriate to shift 2015-2017 rate recovery for marine mitigation to expense rather than capitalization. SCE does not oppose this change, and SDG&E provides no adequate basis for its recommendation that this important detail be left to the discretion of the utilities. Further, we agree with SCE that D.14-11-040 does not address post-2014 mitigation costs, and we are not constrained to categorize later costs according to that decision.

[740] SCE-23 at 17-20.
[741] SDG&E OB at 10-14.
[742] TURN OB at 151-159.

We agree with SCE that compliance with the CDP is a required cost of service. SCE has stated its intention to advocate for a decision from the CCC that it believes will reduce ratepayer costs. We expect SCE to zealously represent ratepayers' interests in all matters of this kind. While we appreciate ORA's desire to align ratepayer and shareholder interests, the record does not identify any clear additional or different action that SCE should take, even if given an incentive to do so, in this instance.

We need not determine here whether or not marine mitigation costs are eligible for reimbursement from the nuclear decommissioning trust. Instead, we simply reiterate that the utilities are not permitted to recover any cost twice. If a cost permitted for recovery here is also recovered from the decommissioning trust (or any other source), SCE and SDG&E shall refund the revenue requirement associated with that cost to ratepayers, with interest.

There is no remaining reason that ongoing costs for either the wetlands or the reef (excluding reef construction) should not be permitted as an O&M expense. We find TURN's forecast for ongoing mitigation costs, $3.703[743] million (2012$), (=SCE's wetlands forecast + TURN's reef maintenance forecast), reasonable and it is approved. Specifically, this amount is included in Section 11.2.1 above.

For reef construction, we agree with TURN that it is premature to approve costs for a compliance-driven project that is not yet required. In the event that CCC does require additional reef construction, or other measures, SCE and SDG&E may file an application to recover costs at that time. In that application, SCE should demonstrate that it has made a reasonable effort to represent ratepayers' interests in front of all applicable regulatory bodies and that its cost

[743] Corrected to 2012$ per SDG&E's Comments at 21.

forecast is reasonable. As decided above, SCE and SDG&E shall recover any such costs as O&M expense, not capital expenditures.

SDG&E's approach for developing its revenue requirement is reasonable, but must be modified to apply to expense rather than capitalization. In its advice letter implementing its revenue requirement, SDG&E shall use the method approved for SONGS expense approved in recent rate case decisions.

11.3. Corporate Security and Business Resiliency (Accounts 920/921 and 923, and Capital Expenditures)

SCE cites four issues leading to increased O&M costs: improving security, emergency preparedness, regulation (NERC CIP), upgrades to security infrastructure. SCE also forecasts capital expenditures due to NERC CIP and security improvements.[744] ORA proposes a 28.6% reduction to SCE's O&M forecast for a variety of reasons, primarily insufficient justification for security force upgrades. ORA also proposes reductions in capital including reductions due to schedule changes in SCE's implementation of NERC CIP and updating the forecast for protection systems based on 2013 spending.[745] In rebuttal, SCE states that it "respectfully disagrees" with ORA's proposals, but accepts them.[746] We find reasonable and adopt ORA's uncontested forecast.

12. Financial, Legal, and Operational Services (FL&OS)

FL&OS consists of a variety of departments and functions. Our total adopted O&M forecast is summarized below (millions of 2012$).

Department/Subject	SCE	Adopted
Financial Services	$ 62.289	$ 54.870
Audit Services Department	$ 8.658	$ 7.721

[744] SCE-7V4.
[745] ORA-18 at 19-40.
[746] SCE-23 at 25-26.

Property and Liability Insurance	$ 94.431	$ 89.308
Legal - Law Department	$ 48.252	$ 45.254
Legal - Claims	$ 23.282	$ 23.082
Legal - Workers' Compensation	$ 21.207	$ 19.736
OS - Planning and Performance	$ 7.339	$ 7.339
OS - Supplier Diversity and Development	$ 1.835	$ 1.835
OS - Corporate Real Estate	$ 48.148	$ 47.172
FLOS, Total O&M	$ 315.441	$ 296.317

Our capital forecast is summarized below (millions of nominal$).

Department/Subject	SCE		Adopted	
	2014	2015	2014	2015
Supply Management	$ 1.058	$ 0.565	$ 1.058	$ 0.565
Transportation	$ 6.179	$ 5.150	$ 6.179	$ 5.150
Corporate Real Estate	$ 94.279	$ 112.090	$ 71.163	$ 80.383
Total	$ 101.516	$ 117.805	$ 78.400	$ 86.098

12.1. Financial Services

SCE forecasts $64.762 million for Financial Services for 2015, which includes (1) maintaining its accounting systems, (2) budgeting and financial forecasting, (3) managing credit and liquidity needs; and (4) compliance with federal and state tax codes. SCE's test year forecast reflects a reduction of $18.003 million from 2012 recorded expenses. The decrease is primarily due to (1) the implementation of organizational changes to improve operational and service quality and (2) use of a five-year-average forecast methodology for Accounts 923/930. Our adopted forecast is summarized below (millions of 2012$).

Account	SCE	Adopted
920/921	27.248	27.248
923/930	35.041	27.622
Financial Services, Total	62.289	54.87

12.1.1. Accounts 920/921

SCE forecast $27.248 million for Financial Services relating to Accounts 920/921, for a reduction of $7.354 million from 2012 recorded expenses. The reduction is primarily due to projected savings from SCE's OpX program which was implemented in 2011 to streamline and improve SCE business processes relating to financial services. TURN does not dispute SCE's forecast for Accounts 920/921.

As part of this program, SCE established Planning & Performance Reporting (P&PR) in December 2012 to centralize finance activities to begin realizing savings associated with centralization. SCE centralized its financial services functions by transferring employees performing finance activities within each operating unit into the Financial Services organization.

ORA recommends a reduction of $1.353 million from SCE's forecast for Accounts 920/921 to reflect additional savings from SCE's OpX Program related to the phrase "Add to fully staff." As discussed in Section 25 below, we reject ORA's proposal to forecast higher OpX savings. No other issues in this area are contested, and we find SCE's forecast reasonable.

12.1.2. Accounts 923/930

SCE originally forecast 2015 expenses of $36.941 million in Financial Services for Accounts 923/930, a reduction of $10.649 million from 2012 recorded expenses. Use of a five-year forecasting methodology in Accounts 923/930 accounted for most of the reduction ($9.335 million).

ORA did not recommend an adjustment to SCE's forecast for Accounts 923/930, other than a reduction of $33,000 for the allocated portion of savings for the OpX "add to fully staff" issue addressed in Section 25 below.

TURN recommends three adjustments related to FERC Accounts 923/930: (1) removal of 50% of Bain consulting costs from the five-year average on the premise it is unlikely to recur (resulting in a $3.3 million TY reduction); (2) use of a two-year average instead of a 5YA for Accounts Payable vendor discounts (using data from 2012 and 2013); and (3) removal of $8.9 million in 2009 tax consulting costs from the five-year average (resulting in a $1.9 million TY reduction) on the premise this expense is non-recurring and was removed in SCE's 2012 GRC.

12.1.2.1. Bain Consulting Costs

SCE's forecast reflects $7.9 million paid in 2011 to Bain & Co. for management consulting to support its OpX initiative, plus $25 million paid in 2012. These amounts represent a large portion of the total costs of consulting support by Bain & Co. for the OpX program. TURN removes 50% of these costs from 2011 and 2012 for forecasting purposes, arguing that this type of extremely expensive endeavor is unlikely to recur at a frequency of every five years and unlikely to recur in the test year and attrition years. TURN's adjustment reduces the forecast for Accounts 923/930 by $3.311 million.

SCE opposes TURN's reduction, claiming that this expense is ongoing and likely to recur, and has appeared in the past two rate case cycles. SCE argues that its OpX initiative is focused on producing customer benefits, so that customers should thus fund the reasonable cost of this effort. SCE argues that TURN's proposed reduction would not provide sufficient resources to continue OpX work.

We adopt TURN's recommendation to exclude 50% of the Bain consulting costs from the 2015 forecast. We find conflicting information in the record concerning SCE's plans for funding Bain consulting costs through 2015 and

beyond. On the one hand, SCE argues that OpX efforts are continuing, and that consultant services will thus likely be needed again (particularly because the staff reductions have resulted in an increased need for outside services). Yet, SCE previously indicated in a data response to TURN that the OpX Initiative concluded in the April 2013 timeframe.[747] SCE also stated in a data response that: "[a]t this time, no additional headcount reductions and associated savings or severance forecasts are planned for 2016 and/or 2017 in IT," and similarly for Customer Service, that "[n]o additional Operational Excellence savings are forecast for 2016 and 2017. All Operational Excellence savings are embedded in the forecast for 2016 and 2017."[748]

We conclude that it is inconsistent for SCE to forecast continuing consulting costs for OpX but not to credit ratepayers with additional savings that will result. We conclude that TURN's proposed adjustment provides a reasonable way to reconcile these conflicts, providing SCE with some degree of continuing consultant funding, but with corresponding recognition of cost savings credited to customers. Adopting TURN's adjustment to Account 923/930 to remove 50% of Bain consulting costs incurred in 2011 and 2012 reduces the forecast for Accounts 923/930 by $3.311 million.

12.1.2.2. Accounts Payable Vendor Discounts

SCE's forecast for Financial Services -- Accounts 923/930 includes a credit of $1.118 million for Accounts Payable Vendor Discounts, based on the 5YA of such discounts (or credits).

[747] Ex. TURN-60 (Financial Services Cross Exhibits), SCE Response to TURN-SCE-018, Q1.a.
[748] Ex. TURN-60 (Financial Services Cross Exhibits), SCE Response to TURN-SCE-004, Q5.f and Q6.e.

TURN recommends that vendor discounts be removed from the 5YA and forecast with a methodology that TURN believes more accurately captures their magnitude. TURN recommends the use of the 2012-2013 2YA for vendor discounts, $5.227 million, which reduces SCE's forecast by $4.108 million.

TURN argues that its proposed adjustment corrects for the effects of overstatement that results from SCE's use of five years of data in developing its forecast of vendor discounts. SCE changed its accounting of these vendor discounts in 2011. SCE had treated these discounts as a revenue item through 2010. Beginning with an accounting change retroactive to January 2011, SCE now treats them as an expense offset. SCE's 5YA thus includes three years with $0 values for vendor discounts, even though vendor discounts existed during those years, because they were accounted for elsewhere in a revenue account as Other Non-Electric Income. SCE's 5YA thus includes only two years of vendor discounts, $2.183 million in 2011 and $3.409 million in 2012, and incorrectly deflates their value in the test year forecast.[749]

SCE opposes TURN's adjustment to reduce the forecast, and to use a two-year average (reliant on unadjusted 2013 data) for Accounts Payable Vendor Discount. SCE claims that use of recorded, unadjusted 2013 costs to forecast Accounts Payable Vendor credits conflicts with the Rate Case Plan and that unadjusted data is inherently unreliable. As with many of the instances where TURN proposes the use of 2013 data in forecasting 2015 test year expense, TURN believes that 2013 data on vendor discounts is more reflective of current conditions, since that year captures benefits of OpX not otherwise credited to ratepayers in SCE's approach.

[749] TURN-5 at 67.

SCE claims that use of 2008-2012 historical average for FERC Accounts 923/930 follows the rate case plan, appropriately relies only on adjusted data, and already results in a significant reduction of $9.335 million. SCE claims it is inconsistent to apply a different forecasting method to one Final Cost Center among many in the same FERC Account simply to lower the forecast, as TURN proposes.

We accept TURN's adjustment to vendor discounts, and conclude that TURN's treatment reflects a consistent approach to analyzing this account. TURN isolated vendor discounts for different treatment because it was the only Final Cost Center for which a 5YA would produce incomplete and inaccurate results. SCE had treated these discounts as a revenue item through 2010, beginning with an accounting change retroactive to January 2011, SCE now treats them as an expense offset. As a result, SCE's 5YA includes three years with $0 values for vendor discounts, even though vendor discounts existed during those years, because they were accounted for elsewhere in a revenue account as Other Non-Electric Income. SCE's 5YA thus includes only two years of vendor discounts, $2.183 million in 2011 and $3.409 million in 2012, and deflates their value in the test year forecast. For this reason, we conclude that in order to produce a more accurate forecast, vendor discounts should be removed from the 5YA and forecast with TURN's methodology.

We conclude that 2013 data on vendor discounts is more reflective of current conditions, since such data captures benefits of OpX not otherwise credited to ratepayers in SCE's approach. We find no reason to ignore 2013 data based on SCE's claim that such data is "unadjusted." In SCE's last GRC (D.12-11-051), we made use of 2010 recorded data even though the Rate Case

Plan was based on use of recorded data only through 2009. As stated in D.12-11-051:

> [W]e adopt 2010 unadjusted, recorded capital expenditures for all business units where these recorded costs were made available during the course of the proceeding. According to the Rate Case Plan, SCE is required to prepare its application based on 2009, not 2010, recorded expenses. However, there is nothing in the Rate Case Plan which limits discovery of 2010 actual recorded expenditures and the Commission finds them informative.[750]

TURN's approach to forecasting Accounts Payable Vendor Discounts increases these credits by $4.108 million and correspondingly reduces the forecast for Accounts 923/930 by the same amount relative to SCE's request.

12.1.2.3. Removal of Tax Consultant Costs

SCE accepted TURN's third recommended adjustment (the removal of $8.9 million of tax consultant costs from 2009 recorded costs).[751] We accordingly adopt TURN's third recommended adjustment for removal of $8.9 million in 2009 tax consulting costs from the five-year average (resulting in a $1.9 million TY reduction) on the premise this expense is non-recurring and was removed in SCE's 2012 GRC.

12.2. Audit Services Department (ASD)

SCE's forecast for FERC Accounts 920/921 for ASD is $8.658 million, a net reduction of $319,000 from 2012 recorded expenses. The reduction reflects the absence of future audit work for the former EIX subsidiary Edison Mission Energy (EME), partially offset by anticipated additional work in Sarbanes-Oxley Act manual key-control testing.

[750] D.12-11-051 at 13.
[751] SCE OB at 250.

ORA proposes a $7.693 million 2015 TY forecast, or $965,061 below SCE's proposal. The proposed reduction reflects ORA's forecast of additional OpX savings (related to the "add to fully staff" issue discussed in Section 25). TURN's forecast for Audit Services – Accounts 920/921 is $7.721 million, a reduction of $937,000 to SCE's request. (TURN's adjustment is independent of the ORA adjustment for OpX.)

TURN argues that the historical years used by SCE (2008-2012 for non-labor and 2012 for labor) are out of sync with the post-EME workload for affiliates, and that SCE did not sufficiently reduce ASD's workload to reflect the work formerly performed for EME. Based on 2013 recorded costs, TURN argues that SCE's 2015 forecast should be reduced further to more accurately reflect the work of Audit Services now that SCE no longer owns EME.

To better capture the impacts of EME's bankruptcy on Audit Services, TURN modifies SCE's forecasting methodology to: (a) separately forecast utility-only costs (net of non-utility affiliate credits) and non-utility affiliate credits, using the 6YA for the former and 2013 recorded affiliate credits for the latter; (b) use a historical average to forecast both labor and non-labor costs, whereas SCE uses 2012 recorded costs for labor; and (c) use a 2008-2013 6YA instead of SCE's 5YA.

In evaluating SCE's assumptions about the reduction in affiliate audit costs in the absence of EME, TURN looked at 2013 recorded non-utility affiliate credits and discovered two interrelated things.

SCE's non-utility affiliate credits for Audit Services dropped precipitously in 2013. Such credits ranged in 2008-2012 from a low of $2.2 million (2012) to a high of $2.7 million (2009). Yet, non-utility affiliate credits in 2013 were only $96,000 (in 2012$). Non-utility affiliate credits for Audit Services in the first

quarter of 2014 were on pace to be even lower than in 2013. This reduction of approximately $2.1 million from the lowest year, 2012, was much greater than that anticipated by SCE for affiliate audit costs in 2013 of $743,000, as well as in 2015 of $960,000. Based on these figures, TURN argues that non-utility affiliate credits should be forecast at 2013 levels.

TURN also forecasts Audit Services costs other than non-utility affiliate credits using a 2008-2013 6YA, as opposed to SCE's approach. Excluding affiliate credits, these costs have fluctuated within a $600,000 range from 2008-2011 and in 2013 (varying from $7.975 million to $7.363 million), though costs were lower in 2012.

TURN includes 2013 recorded costs in this average because these costs reflect the changing volume of work of Audit Services. Audit Services utility-only costs increased by about $1 million in 2013 over 2012 levels. According to SCE, Audit Services was to absorb additional work related to Sarbanes-Oxley Act manual key-control testing beginning in 2013, due to the centralization of some processes. Likewise, 2013 recorded costs capture the cost impacts from the EME bankruptcy (other than less affiliate audit work) highlighted by SCE in its rebuttal testimony, such as the loss of cost-sharing with EME for Audit Services functions that are not eliminated.

SCE claims that TURN's approach assumes that ASD can eliminate costs on a dollar-for-dollar basis based on previous EME affiliate credits (which included fixed costs, a labor mark-up, and allocations for corporate support functions). SCE now bears the entire cost of the ASD, rather than sharing it with EME. For instance, SCE claims that the size of ASD declined, but SCE now pays the entire cost of the General Auditor.

We find that TURN's forecast of ASD expenses, $7.721 million in Accounts 920/921, is reasonable. Recorded data from 2013 and early 2014 suggest significant declines in affiliate credits following the EME bankruptcy. TURN's approach of forecasting ASD expenses based solely on utility-only costs is a reasonable approach to forecast costs in light of the bankruptcy.

12.3. Property and Liability Insurance (Accounts 924 and 925)

SCE's 2015 TY forecast for property and liability insurance is $94.431 million (reflecting removal of SONGS and Four Corners costs). The property insurance forecast in FERC Account 924 is $18.973 million and the liability insurance forecast in FERC Account 925 is $75.458 million.[752] TURN did not comment on SCE's insurance forecast.

ORA does not dispute SCE's forecast for Account 924. For Account 925, however, ORA recommends removal of $4.990 million, arguing that SCE has not removed all SONGS and Four Corners costs. ORA states that the $4.98 million was for SONGS when it was operational. ORA argues that SCE's removal of $4.990 million, only to re-allocate it to Corporate so that SCE can still collect it from ratepayers is not what the Scoping Memo ordered.[753]

SCE responds that its calculation of the SONGS portion of excess liability insurance expense was updated to incorporate the correct headcount reflecting SONGS in a shut-down state and the change in the participants' share of the cost. SCE claims it removed the entire portion of SONGS and Four Corners insurance costs.[754]

SCE's uncontested forecast of property insurance in Account 924 of $18.973 million is reasonable and is approved. ORA's recommendation to reduce the

[752] SCE-24V1P2 at 1.
[753] ORA-19 at 37-39.
[754] SCE-24V1P2 at 1-4.

liability insurance forecast in Account 925 to $70.335 million is reasonable for two reasons. First, there is no dispute that the difference is a SONGS cost. Second, SCE's testimony on the subject is inconsistent. SCE states that the total premium forecast has not changed, but that the allocation of the premium among SCE's business units is related to the number of employees. SCE has not explained why the total premium forecast did not decline along with the number of total employees.

12.4. Legal

SCE forecasts $92.741 million for the Legal Operating Unit, consisting of $48.252 million for the Law Department including Corporate Governance, $23.282 million for the Claims Department, and $21.207 million for the Workers' Compensation Department.

12.4.1. Law Department

SCE forecasts $48.252 million for the Law Department: Law's FERC Accounts 920/921/923/925/928 and Corporate Governance's FERC Account 930. ORA recommends a reduction of $2.698 million. TURN recommends a reduction of $1.999 million. Our adopted forecast is summarized below (millions of 2012$).

Account	Activity		SCE	Adopted
920/921	In-House	Total	$ 30.539	$ 30.539
		Labor	$ 25.245	$ 25.245
		Non-Labor	$ 5.294	$ 5.294
923/925/928	Outside Counsel	Total	$ 14.503	$ 12.503
		Labor	$ -	$ -
		Non-Labor	$ 14.503	$ 12.503
930	Corporate Governance	Total	$ 3.210	$ 2.212
		Labor	$ 0.014	$ 0.014
		Non-Labor	$ 3.196	$ 2.198
Law Department, Total		Total	$ 48.252	$ 45.254

	Labor	$ 25.259	$ 25.259
	Non-Labor	$ 22.993	$ 19.995

12.4.1.1. FERC Accounts 920/921: In-House

SCE's forecast for Accounts 920 and 921 for in-house costs is $30.539 million, $1.457 million below 2012 recorded.[755] ORA recommends that SCE's In-House forecast be reduced by $98,000 to reflect SONGS' share of the Financial Services centralization savings.[756] We reject ORA's argument as discussed in Section 25 below. SCE's forecast for Accounts 920 and 921 for in-house costs of $30.539 million is reasonable and is approved.

12.4.1.2. FERC Accounts 923/925/928: Outside Counsel

SCE's forecast for Accounts 923, 925, and 928 is $14.503 million for outside counsel expenses, based on recorded costs from 2012.

Three areas of controversy exist regarding outside counsel costs: (1) ORA proposes that SCE's incentive payments be removed from its forecast; (2) ORA removes expenses related to the Grass Valley Fire; and (3) TURN proposes to utilize years 2008, 2009, and 2012 for averaging instead of SCE's proposal of 2012 recorded costs. Of these three proposed adjustments, we adopt two: (1) and (3). We note that the sum of these two adjustments individually is $2.538 million. However, the record before us does not clearly demonstrate the impact of these two adjustments in combination, which is likely less than the sum of the two parts due to interactive effects. Therefore, we estimate an adjustment of $2 million and adopt a forecast of $12.503 million for outside counsel.

[755] SCE-24V2 at 3.
[756] ORA-19 at 3, 17-18.

12.4.1.2.1. Outside Counsel Incentive Payments

SCE's forecast for Account 923 includes incentive payments provided to seven strategic law firms. ORA recommends removing the incentive payments from SCE's 2015 forecast in the amount of $1.538 million. Under SCE's incentive program, SCE's strategic law firms can earn discretionary payments when providing exceptional legal work beyond the high level of work already expected, being efficient in such work, adhering to budgets, and/or providing diverse legal teams. SCE argues that such incentives encourage outside counsel to provide an exceptionally high level of services benefiting both SCE and its customers. The Commission recognized such benefit when it stated "[i]t may be reasonable to provide incentives to outside counsel to motivate them to achieve good results." Therefore, SCE argues that the incentive payments are properly included in SCE's outside counsel forecast.

D.12-11-051 stated that:

> It may be reasonable to provide incentives to outside counsel to motivate them to achieve good results. Combined with reduced fees, it may result in lower costs and revenue requirement. Therefore, we find that these are ordinary recoverable business costs. However, to receive recovery in future GRCs, SCE shall provide information to support that it is obtaining base fees at discount compared to market.[757]

ORA claims the only support SCE provided in its testimony in this GRC is a chart that compares "Real Rate Report to Edison,"[758] but has not provided verifiable information that, with these discretionary bonuses, SCE is obtaining base fees at a discount. ORA thus opposes SCE's request for ratepayers to fund them in TY 2015. ORA removed discretionary bonuses from the 2008-2012

[757] D.12-11-051 at 490-491.
[758] Ex. SCE-08, Vol.2 at 16, Figure II-4.

recorded adjusted costs before forecasting for TY 2015. ORA forecasts $12.973 million for Outside Services for TY 2015.

SCE disputes ORA's claim that SCE provided no support that it is obtaining base fees at discount compared to the market. SCE cites to a copy of a confidential report that SCE provided to TURN.[759]

SCE claims it provided ORA with supporting documentation detailing how outside counsel rates paid by SCE are lower on average than the market. ORA claims, however, that SCE refused to disclose partner and associate rates and contracted fees for 2008 -2013, and that the information was provided about SCE's bonus payment determinations is hardly an objective process. ORA expresses doubt that SCE is actually obtaining base fees at discount compared to market. ORA claims that SCE's request to make its ratepayers pay for unjustified discretionary bonuses should be denied.

We adopt ORA's proposed reduction. As we stated in D.12-11-051, it may be reasonable to provide incentives to outside counsel to motivate them to achieve good results. We conclude, however, that SCE has not met its burden of proof as called for in D.12-11-051, to support that it is obtaining base fees at discount compared to market.

12.4.1.2.2. Grass Valley Fire Outside Counsel Costs

SCE's forecast includes outside counsel costs in defending itself in litigation arising from a fire that occurred in Grass Valley. ORA argues that such costs should be removed from the forecast. ORA makes a similar claim related to the forecast of claims discussed in Section12.4.2.2 below. ORA's basis for seeking removal is that a civil party litigant made an allegation of SCE wrongdoing.

[759] SCE-24V2 at 6-7.

ORA admits, however, that the civil case settled and SCE was not found liable of wrongdoing, nor did SCE admit any fault when settling. SCE claims there is no legal basis to remove the Grass Valley Fire costs from forecasting. The Grass Valley Fire litigation was a typical fire-related action filed against SCE. As with most fire-related actions, negligence and inverse condemnation was pled. Under California law, a successful inverse condemnation claim results in a party paying for property damage and the costs are to be socialized via rates. SCE argues that ORA has presented no reason why the Grass Valley Fire should be treated any differently.

SCE argues that the Grass Valley Fire costs should not be removed from forecasts as there has been no judicial finding of SCE fault in the Grass Valley Fire. Since practically all litigants allege wrongdoing in civil lawsuits, SCE argues that an allegation alone cannot be a basis for cost removal.[760]

We find that SCE's proposal to include these costs is reasonable. Absent a finding of error or fault, it is reasonable to include costs related to litigation resulting from fires. As we noted previously, however, in the event SCE is later found to be in error or fault, the Commission may take appropriate action to restore these funds to the ratepayers.[761]

12.4.1.2.3. TURN's Forecasting Methodology

To forecast outside counsel costs, SCE used 2012 recorded expenses. SCE defends use of this method given the downward trend in such costs from 2010-2012. TURN recommends funding outside counsel expenses at a level of $13.503 million, for a reduction of $1.000 million to SCE's forecast. TURN proposes a forecasting based on the average of the 2008, 2009 and 2012 recorded figures, and removal of the 2010 and 2011 figures from the average. TURN

[760] SCE-24V2 at 7-8, 18-21.
[761] See D.12-11-051 at 498.

claims that SCE failed to adequately explain the high levels recorded in those years or to demonstrate their reasonableness.

TURN labeled the amounts for 2010 and 2011 as "outliers," since each year was 22-31% higher than the next highest recorded figure during 2008-2012. The Commission has previously removed outlier or anomalous years from averages of recorded data or made similar adjustments to develop a reasonable forecast.

SCE claims that TURN's proposal is arbitrary, and that the Commission has directed what methodologies should be utilized given historical data and SCE's forecast is based on such direction. SCE argues that simply averaging "good" years is not proper.

We accept TURN's adjustment as appropriate, and conclude that 2010 and 2011 data are not reliable as a basis to develop test year forecasts. We do not consider it "arbitrary" to exclude cost data from the development of the test year forecast if such exclusion produces a more reliable forecast. The burden is on SCE to establish the reasonableness of including the 2010 and 2011 costs for forecast purposes. We conclude that SCE failed to meet that burden. The recorded figures for the 2010-11 period reflect largely unexplained and unjustified increases as compared to the 2008-09 period. SCE has not explained why the costs were so much higher in 2010 and 2011, nor demonstrated that the higher costs are likely to recur going forward. Absent an adequate explanation from SCE, we exclude those years from the basis for the test year forecast, and reduce SCE's forecast by $1.000 million, as proposed by TURN.

12.4.1.3. FERC Account 930: Corporate Governance

SCE's 2015 forecast for Corporate Governance Account 930 is $3.210 million.

ORA and TURN recommend that $998,095 be subtracted from SCE's 2015 forecast to disallow recovery of SCE's Board of Directors' ("Board") supplemental benefits and stock-based compensation. ORA claims that the Board does not benefit customers. TURN contends that SCE did not prove the reasonableness of the costs.

SCE claims that an analysis completed by an independent consultant, Frederick W. Cook & Co., proves that both the Board's total compensation and equity compensation are reasonable. The Commission previously held "that as long as total compensation levels are appropriate, we will not dictate how … [a utility] distributes compensation among various types of employment benefits."

SCE has also put forth evidence demonstrating that the Board benefits the customers by reviewing proposals and reports on major capital projects, thereby increasing the safety and reliability of SCE's facilities and by ensuring that SCE's operations are cost-efficient. Given that California law requires that corporations have board of directors, SCE argues that all of its Board compensation and benefits should be recovered as normal costs of doing business.

ORA argues that SCE offers no proof to support the claim that this compensation is necessary to attract and retain highly skilled and qualified Board members which ultimately benefits ratepayers. ORA claims there is lack of proof connecting such costs to SCE's ability to "obtain experienced outside directors." ORA characterizes SCE's arguments about how experienced Board Members "ultimately benefits ratepayers" as "unsubstantiated trickle-down economic theory with no basis in fact."

TURN also opposes rate recovery of these expenses. In addition to arguments raised by ORA, TURN claims SCE's request is almost entirely a rehash of the request made (and rejected) in the 2012 GRC. TURN claims that

SCE failed to demonstrate the reasonableness of the requested amount, given the cost forecast increases of 24% for per-director compensation and 50% for stock options as compared to the 2012 GRC request.

We adopt the proposal of ORA and TURN to disallow SCE's Board supplemental benefits and stock-based compensation, and thus subtract $998,095 from SCE's 2015 test year forecast.

SCE did not substantiate its claim that the Board's review of SCE's activities promotes cost efficiency that serves ratepayer interests. As indicated by SCE's Corporate Governance Guidelines, the primary functions of the Board include representing the interests of shareholders, and acting in the interests of shareholders whenever there are conflicting interests among shareholders, customers, and the general public.[762]

Where a utility requests the same relief that was denied in a previous GRC, the utility must explain what has changed to warrant a different outcome in the present case. Significant portions of SCE's direct testimony in this 2015 GRC are similar to corresponding 2012 GRC testimony.[763] As previously indicated in SCE's 2012 GRC, whether an expense is part of SCE's business model is a separate question from whether the costs are necessary for the delivery of electric service.[764] We find SCE's claims unpersuasive that the Board's review of SCE's activities and purported benefits necessarily warrants ratepayer funding. Under these circumstances, we reach the same conclusion on this topic that previously reached in SCE's 2012 GRC, and deny SCE's funding request.

[762] TURN-59 (SCE Corporate Governance Guidelines), pp. 1 and Exhibit A-2, p. 1; Swartz, SCE, 11, RT 1133, l. 27 to 1134, l. 13.
[763] Compare SCE-8V2 at 20-23 with the testimony in TURN-58 (Excerpt of 2012 GRC testimony).
[764] D.12-11-051 at 494.

12.4.2. Claims

The Claims Department administers many claims each year, including claims on behalf of SCE and against SCE. Our adopted forecast is summarized below (millions of 2012$).

Account	Activity		SCE	Adopted
920/921/ 924	Administrative and General	Total	$ 3.858	$ 3.658
		Labor	$ 3.057	$ 3.057
		Non-Labor	$ 0.801	$ 0.601
925	Reserves	Total	$ 19.424	$ 19.424
		Labor	$ -	$ -
		Non-Labor	$ 19.424	$ 19.424
Claims Department		Total	$ 23.282	$ 23.082
		Labor	$ 3.057	$ 3.057
		Non-Labor	$ 20.225	$ 20.025

12.4.2.1. FERC Account 920/921/924: Claims Administrative and General

SCE's 2015 forecast for Claims FERC Accounts 920/921/924 is $3.858 million. ORA does not dispute SCE's forecast.

SCE includes $400,000 of lease costs for a 44,000 square foot indoor storage facility to properly retain and safeguard evidence related to investigations, per the Commission's own rules and SED's interpretation of such rules. TURN disputes such costs. TURN claims that SCE failed to demonstrate that it needs the storage facility.

SCE claims it urgently needs a proper indoor storage facility, and that its current facilities are inadequate and filled to capacity. SCE explains that it plans to build an SCE-owned storage facility in 2017 to meet this need; the lease requested now is temporary.[765]

[765] SCE-24V2 at 15-17.

We partially approve SCE's request for funding for an indoor storage facility. We are not persuaded that SCE has fully justified the reasonableness of obtaining a large central indoor repository for storage of failed utility equipment, rather than continuing its current practice of storing that equipment at various SCE sites and, as needed, at leased locations on an ad hoc basis. The incremental cost of such a leased outdoor space appears to be on the order of $3,000 per month, and SCE is leasing "a couple" at this time.[766] TURN asserts that ratepayers would be better off were SCE to incur incremental costs of $9,000 per month (for three such outdoor facilities). The total cost would be approximately $108,000 per year, rather than the $400,000 annual expense SCE seeks for the lease of the indoor facility.[767]

We deny $200,000 of SCE's request. It is reasonably necessary for SCE to have access to secure space to store evidence. This amount of funding will cover the costs for a greater number of outdoor sites, a smaller indoor facility, or some combination of the two. While we support the prioritization of retaining evidence for important investigations, we encourage SED to work with SCE to ensure that only relevant evidence is retained and allowing other items to be discarded, reused, etc.

12.4.2.2. FERC Account 925: Claims Reserves

SCE forecasts $19.424 million for FERC Account 925, Claims Reserves. SCE's forecast is based on a 5YA of historical costs due to the significant cost fluctuations from year-to-year, and the unpredictable nature of Claims Reserve costs.

[766] Ramos, SCE, 11 RT at 1169, l. 29 to 1170, l. 8.
[767] TURN OB at 177-179.

ORA recommends that $976,000 paid towards settlement of the Grass Valley Fire be removed from Claims Reserves for forecasting purposes (see Section 12.4.1.2.2. above.[768]

TURN's forecast is $16.727 million, a reduction of $2.697 million from SCE's request.

TURN derived its forecast by removing recorded costs for 2009 and using a four-year average, claiming that the 2009 figure is an outlier compared to amounts during 2008-12. TURN also added back to the recorded figure for 2011 the $7.5 million offset that occurred that year due to a one-time credit from the Mohave-related settlement. The average of these amounts for 2008 and 2010-2012 is $16.727 million. In the alternative, TURN recommends that 2012 costs be utilized for forecasting, which would yield a forecast of $17.631 million. TURN claims that use of the recorded 2012 amount is consistent with SCE's approach to forecasting outside counsel expenses when the recorded amounts in 2008-2012 showed a similar pattern over that period. This alternative would reduce SCE's forecast by $1.793 million. TURN also raises a policy question related to ORA's proposal to exclude Grass Valley costs.[769]

SCE claims that both of TURN's proposals defy this Commission's forecasting methodology directives. SCE claims that removing all of 2009 costs from averaging is "cherry-picking" that should not be allowed. SCE argues that because claims reserves are highly unpredictable with large variations year to year, averaging is appropriate. SCE claims that this Commission has indicated that the appropriate forecast methodology for accounts with significant

[768] ORA-19, ORA-26.
[769] TURN OB at 173-177.

fluctuations and those influenced by unpredictable external factors is averaging--not the last recorded year.[770]

The Commission has previously removed or otherwise adjusted outlier years in the development of a forecast based on averaging of recorded years' data. TURN is not arguing that any and all outlier years should be removed from averages. TURN asserts that SCE could have presented testimony explaining the underlying circumstances that caused the recorded figure in the outlier year to be as high as it was and, in doing so, potentially demonstrate that it was reasonably included in the recorded data relied upon to develop the test year forecast.[771]

We reject both TURN and ORA's arguments and approve SCE's forecast. A 5YA forecast is a reasonable approach to forecasting accounts with high variation in recorded costs. SCE's forecast of $19.424 million for Account 925, Claims Reserves is reasonable.

12.4.3. Workers' Compensation (Account 925)

SCE forecasts $21.2 million for FERC Account 925, consisting of $7.0 million for Workers' Compensation staff expenses and $14.2 million for Workers' Compensation Reserves. ORA does not dispute SCE's $21.2 million forecast; TURN opposes the reserves portion. The staff portion of Workers' Compensation is undisputed and we find it reasonable. Our total adopted forecast is summarized below (millions of 2012$).

[770] SCE OB at 256-257.
[771] TURN OB.

Account	Activity		SCE	Adopted
925	Staff	Total	$ 7.029	$ 7.029
		Labor	$ 3.833	$ 3.833
		Non-Labor	$ 3.196	$ 3.196
925	Reserves	Total	$ 14.178	$ 12.707
		Labor	$ -	$ -
		Non-Labor	$ 14.178	$ 12.707
Workers' Compensation		Total	$ 21.207	$ 19.736
		Labor	$ 3.833	$ 3.833
		Non-Labor	$ 17.374	$ 15.903

SCE's Reserve forecast is based on a 5YA due to cost fluctuations and the unpredictable nature of reserves. TURN agrees with SCE that a historical average is appropriate but recommends the exclusion of 2008 and inclusion of 2013. TURN's forecast, based on the 2009-2013 5YA, is $12.707 million, which is $1.471 million less than SCE's forecast.[772]

We adopt TURN's reduction of $1.471 million, based on use of a 2009-2013 5YA. SCE's costs dropped precipitously after 2008 and have remained lower. In SCE's 2012 GRC, the Commission recognized that 2008 costs were out of line with the subsequent years and rejected SCE's theory that the outcome of pending workers' compensation litigation might reverse the downward trend in reserve expenses, finding this potential "too speculative" to justify the inclusion of 2007-2008 in the forecast.[773] We authorized a forecast of $14.77 million for 2012, more than enough to meet SCE's actual reserve expenses of $13.624 million.

SCE claims that 2008-2012 recorded data is a complete and accurate data set to use for forecasting. SCE claims it is inappropriate to ignore a certain year because of higher costs that year and utilize an incorrect and unadjusted year simply to arrive at a lower number. SCE argues that 2013 data has not been

[772] SCE-OB at 257.
[773] D.12-11-051 at 501.

adjusted, is inappropriate for rate-making purposes, and does not adjust for a $2.7 million insurance recovery (associated with insurance recovery for "the Rivergrade and burn incidents"), which would result in a 2013 amount of $9.687 million instead of TURN's initial $6.987 million. SCE argues that the preliminary adjustment of $2.7 million may not be the only adjustment to 2013 recorded costs, and until all adjustments are accounted for, 2013 numbers should not be included in the forecast.[774]

TURN however accepts this 2013 adjustment in errata.[775] TURN notes that SCE's adjustments to workers' compensation reserve expenses have been small as a percentage of total recorded costs (less than 0.5%) in each year from 2008-2012, with the exception of 2012. Based on the magnitude of SCE's adjustments to data since 2008 – with the exception of those for the Rivergrade and burn incidents – it is reasonable to expect that SCE might find other small adjustments to 2013 recorded costs that could increase or decrease costs by 0.5% or so, or about $50,000.

Given these considerations, we find it reasonable to include 2013 recorded costs in the average to forecast SCE's 2015 reserve expenses. We note that this includes both the 2012 and 2013 for the Rivergrade and burn incidents.

12.5. Operational Services

Operational Services (OS) is comprised of four departments: CRE, PPO, Supplier Diversity and Development, and Transportation. For OS's O&M expenses, SCE forecast $57.322 million in 2015, a 6.86% decrease under 2012 recorded/adjusted levels.

The total OS capital expenditure forecast for 2013-2017 totals $544.49 million and includes funding for: CRE, Transportation and Supply Management.

[774] SCE-24V2 at 23-24.
[775] TURN-3A.

SCE forecasts a cumulative $312.343 million in OS capital expenditures over the 2013-2015 period.[776]

12.5.1. Operational Services O&M (other than CRE)

SCE forecast $7.339 million in FERC 920/910 for OS Planning and Performance Organization (PPO) and $1.835 million for OS Supplier Diversity and Development Department (SDD). O&M expenses for Transportation were not included in OS' forecast as those costs are charged back to other SCE Operating Units and included in those respective Operating Unit's recorded costs and forecasts.[777] No party challenged SCE's TY forecast for PPO and SDD, and we find PPO's forecast of $7.339 million and SDD's forecast of $1.835 million reasonable and they are adopted.

12.5.2. Operational Services Capital (other than CRE)

No party challenges SCE's OS forecast of non-CRE capital projects for 2014-2015. Accordingly, we adopt the SCE's capital expenditure forecast for non-CRE OS projects from 2014-2015 totaling $12.952 million.

12.5.3. SBUA Proposal to Track Spending with Small Businesses

SBUA proposes that SCE track and publish information on its spending with small businesses.[778] We agree with SCE that, if this proposal is to be implemented, it should be done on a statewide basis. If SBUA chooses to pursue this proposal further, it should do so in a generic rulemaking such as R.14-10-009 so that all relevant stakeholders may participate.

12.5.4. CRE O&M

Our adopted forecast of CRE O&M is summarized below (2012$ millions).

[776] SCE OB at 258.
[777] SCE OB at 259.
[778] SBUA OB at 8-10.

FERC Account	SCE Rebuttal	Adopted
920/921(Labor)	$ 14.347	$ 14.120
920/921 (Non-Labor)	$ 11.781	$ 10.037
931 (Non-Labor)	$ 11.115	$ 11.115
935 (Non-Labor)	$ 10.905	$ 10.905
935 (Non-Labor) - Rancho Cucamonga Office Building Optimization	$ -	$ 0.995
Total CRE O&M	$ 48.148	$ 47.172

12.5.4.1. FERC Accounts 920/921

CRE records labor and non-labor expenses for managing SCE's nonelectric facility portfolio (226 buildings) to FERC Accounts 920/921. SCE's TY 2015 forecast of $26.13 million for CRE was based on a three-year average of recorded costs. SCE claims that ORA's and TURN's forecasts do not accurately reflect CRE's projected expenses.

ORA recommends using 2012 recorded levels of CRE's non-labor forecast resulting in $4.860 million reduction. SCE claims ORA's recommendation fails to consider that CRE's 2012 level of spending was unsustainable and increased non-labor costs are needed to restore sustainable levels of facility maintenance and to address the significant increase in employee moves arising from organizational realignments and exiting leased facilities and the need for more contingent workers and outside services due to CRE's reduced workforce.[779]

TURN recommends reducing CRE's TY forecast for labor and non-labor costs by $2.371 million. TURN utilizes a three-year average of costs recorded from 2011-2013 to forecast CRE's labor and non-labor expenses along with retroactive application of future year Operational Excellence savings to 2011 and 2012 recorded costs.[780] SCE claims that : (1) TURN's use of 2013 unadjusted data

[779] SCE OB at 259-260.
[780] TURN OB at 184-186.

inappropriately excluded approximately $2 million of 2013 expenses and an additional $640,000 of 2013 affiliate credits; (2) CRE's forecast already reflects a downward future-year adjustment for Operational Excellence savings and TURN's application of the same adjustment to 2011-2012 results in double-counting the savings; and (3) TURN relies on an incorrect calculation of CRE 2013 recorded costs as the basis to discount SCE testimony detailing the reasons for CRE's higher non-labor forecast.[781]

We decline to adopt ORA's proposed use of 2012 data for forecasting. We find it inconsistent that ORA accepted CRE's lower TY labor forecast (FERC 920) due to reduced staffing, but did not accept the corresponding increases in CRE's non-labor costs (FERC 921) associated with such reduced staffing.

We conclude, however, that TURN's use of a three-year average is appropriate and adopt that approach. We are not persuaded by SCE's objections to TURN's methodology.

We find no double-counting in TURN's methodology. SCE's labor cost forecast for 2013 included $1.222 million to reflect a work force reduction that would not occur until 2013. To ensure that the full amount of those forecasted savings flowed to ratepayers in 2015, they needed to either be reflected in each year's data (the approach TURN took) or added back to the 2013 data, then removed from the resulting average. Mathematically, the result is the same, and the $1.222 million adjustment appears once, not twice. SCE does not show that its forecast applies the full value of this savings to 2015 forecast, and thus does not show how TURN's adjustment should be considered double counting.

SCE also claims that TURN's use of unadjusted 2013 data fails to reflect affiliate credits that would cause 2013 unadjusted recorded costs to appear

[781] SCE OB at 260.

approximately $640,000 lower as compared to 2013 adjusted costs. As TURN notes, however, a non-utility affiliate credit adjustment is not essential in developing a 2015 forecast. With the sale of the Edison Mission Energy assets to NRG, SCE is the only subsidiary of EIX generating any material funds. This is why the 2013 affiliate credits figure SCE reported in rebuttal testimony is substantially below the 2011 and 2012 figures for this account. EIX and other affiliates, however, will continue to create affiliate credits for SCE.[782]

SCE identified 2013 recorded amounts associated with cost centers that were not reflected in TURN's calculation of 2013 recorded costs. TURN addressed this in errata, increasing the 2013 recorded cost figures by $907,000 for labor and $1.391 million for non-labor, with corresponding increases to the three-year average calculated for 2011-13. However, TURN's showing is inconsistent on this point, showing different values in OB and TURN-8A.

SCE claims its increased O&M forecast in 2015 is justified in part because it added facilities in 2009-12 based on a headcount that is now a thing of the past. But SCE readily acknowledges that one result of its non-electric facilities boom of recent years is that the utility expects to have 6.2 million square feet of non-electric facilities for a work force that would reasonably be expected to require five million square feet, an excess of 24%[783]. TURN submits that even if the 2013 recorded costs had not come in so far below SCE's forecasts for that year, casting doubt on the validity of the utility's assumptions and calculations for the 2015 forecast, the increase SCE seeks for 2015 should be rejected to mitigate the ratepayer impact of a building fleet sized for a work force that is nearly a quarter larger than the one SCE now expects to have in place.[784]

[782] SCE RB at 127.
[783] 11 RT 1184-1186.
[784] TURN OB at 186.

In conclusion, we accept TURN's premise that a 3YA, with adjustments for OpX savings is reasonable. However, we find that further adjustments to TURN's forecast are necessary to account for affiliate credits and excluded cost centers. We estimate the combined impact of these adjustments as $1.200 million in 2013, and thus $0.400 million to the 3YA of non-labor. Our adopted forecast is $14.120 million in labor, and $10.037 million in non-labor.

12.5.4.2. Rents (Account 931)

CRE records expenses in FERC Account 931 for rental and lease costs of non-SCE owned property and buildings. SCE's TY2015 forecast of $18.106 million was based on rent payments, lease escalations, and other charges per actual lease agreement terms. Subsequent to filing its GRC Application, SCE finalized plans to exit certain leased facilities, either in whole or in part, with terms expiring in 2015 and 2016.

TURN recommends normalizing the expected 2015-2017 lease savings based on updated plans, which results in a $10.95 million forecast ($7.139 million below SCE's forecast).

SCE agrees with TURN's proposal relative to normalizing the expected 2015-2017 lease savings. SCE requests a higher forecast of $11.115 million, however, (approximately $164,000 above TURN's forecast) based upon certain additional costs arising from a lease negotiated subsequent to TURN's submission of testimony.[785] SCE requests that the Commission authorize TY funding in FERC Account 931 of $11.115 million, a net decrease of $6.991 million from the original TY forecast. TURN accepts SCE's modification to the TURN-proposed figure, and the resulting forecast of $11.115 million.[786] We adopt the $11.115 million forecast, as mutually agreed by SCE and TURN.

[785] SCE OB at 260-261.
[786] TURN OB at 183-184.

12.5.4.3. Non-Labor Repairs and Maintenance (Account 935)

CRE's FERC Account 935 is for non-labor repairs and maintenance (non-capital) of facility structures and parking areas that SCE owns, uses, occupies, or operates, including repairs to infrastructure and equipment. SCE's TY forecast of $10.905 million is $3.2 million over the 2012 costs and is based on a three-year average. The increase is primarily attributable to the increase in critical facility maintenance resulting from the addition of the Alhambra Data Center and restoration of sustainable maintenance at SCE's other critical facilities.

ORA's proposed $9.705 million forecast is based on 2012 recorded spending levels ($7.7 million) plus a $2 million increase in support of higher levels of critical facility maintenance.

Similar to CRE's forecast for FERC Accounts 920/921, SCE claims that ORA fails to account for (1) substantial fluctuations in recorded expenses for this account during the 2008-2012 period (rendering a LRY an inappropriate base) and (2) SCE's uncontested showing that 2012 maintenance levels are unsustainable and restoration of proper maintenance levels at critical facilities is essential to support the IT and telecom equipment housed at these sites.

We adopt SCE's forecast of $10.905 million for CRE's FERC Account 935 for non-labor repairs and maintenance (non-capital) of facility structures and parking areas that SCE owns, uses, occupies, or operates. Given the level of variation in recorded data, SCE's 3YA is appropriate.

12.5.5. CRE Capital

CRE projects support SCE's non-electric facility portfolio housing SCE's workforce and equipment and maintain the performance and lifecycle of SCE non-electric facility assets and infrastructure. ORA and TURN only provide

recommendations on CRE's capital forecast for the period from 2013 through 2015. SCE accepts ORA's and TURN's corresponding recommendations to adopt 2013 recorded expenditures in place of the 2013 forecast, but rejects their recommendations for CRE's 2014-2015 capital forecast. As noted in Section 5.2 above, we approve use of 2013 recorded capital.

ORA accepts SCE's forecast of CRE capital expenditures for 2014-2015, except for: (1) the Irwindale Business Center (IBC) Remodel; and (2) the IT Equipment and Infrastructure Blanket. ORA's recommendations reduce CRE's 2014-2015 capital forecast by $33.330 million.

TURN challenges SCE's 2014-2015 forecast relative to the following CRE projects: (1) Emergency Operations Center; (2) General Office 2 (GO2) Conference/Training Center; (3) GO5 Parking Structure; (4) IBC Remodel; (5) Rancho Cucamonga Lease Optimization; (6) Capital Maintenance Blanket; (7) Ongoing Furniture Modification Blanket; (8) Energy Efficiency Blanket; (9) Garage Infrastructure; Upgrade Program; (10) Service Center Infrastructure Upgrade; (11) IT Equipment and Infrastructure Blanket; and (12) Corporate Communications Media Center. TURN also seeks removal of certain amounts included in the CRE project forecasts tied to contingency. In total, TURN recommends reducing CRE's 2014-2015 capital forecast by $107.163 million.

Our adopted forecast is summarized below:

Project	2014			2015		
	Requested	Adopted		Requested	Adopted	
		Pre-Adjustment	Post-Adjustment		Pre-Adjustment	Post-Adjustment
Emergency Operations Center (EOC)	$ -	$ -	$ -	$5.000	$5.000	$4.524
GO2 Conference &	$0.300	$0.300	$0.271	$0.700	$0.700	$0.633

Training Center						
GO5 Parking Structure	$4.700	$ -	$ -	$6.200	$ -	$ -
Irwindale Business Center (IBC)	$ -	$ -	$ -	$20.000	$17.000	$15.383
Rancho Cucamonga Office Building Optimization	$ -	$ -	$ -	$3.300	$1.100	$0.995
Capital Maintenance	$20.446	$20.446	$18.501	$20.912	$20.912	$18.922
Ongoing Furniture Modifications	$2.916	$2.916	$2.639	$2.982	$2.982	$2.698
Energy Efficiency Blanket	$2.500	$2.500	$2.262	$2.614	$2.614	$2.365
Garage Infrastructure Upgrade Program	$5.112	$2.585	$2.339	$5.228	$2.585	$2.339
Service Center Infrastructure Upgrade Program	$10.223	$3.500	$3.167	$10.456	$3.500	$3.167
Corporate Communications Media Center	$1.000	$ -	$ -	$ -	$ -	$ -
Other Non-Blanket Projects	$41.053	$41.053	$37.147	$27.166	$27.166	$24.582
Other Blanket & Projects Under 1 million	$0.383	$0.383	$0.347	$0.392	$0.392	$0.355
Subtotal	$88.633	$73.683	$66.673	$104.950	$83.951	$75.964
Less: Blankets	$(41.580)	$(32.330)	$(29.254)	$(45.884)	$(34.085)	$(30.842)

& Projects Under 1 million						
Total for Calculating IT Adder	$47.053	$41.353	$37.418	$59.066	$49.866	$45.122
IT Adder (12%)	$5.646	$4.962	$4.490	$7.088	$5.984	$5.415
Grand Total	$94.279	$78.645	$71.163	$112.038	$89.935	$81.379
Capital Expenditure			$71.163			$80.383
Treated as O&M			$-			$0.995

12.5.5.1. Contingency Funding and Project Management Costs

TURN makes two recommendations that are applicable to many of the specific CRE projects discussed below: disallowance of contingency funding and disallowance of project management costs.

SCE has included contingency amounts in its CRE capital expenditure forecasts, both in the planning estimates for particular projects and as separate adders to the forecasts for its energy efficiency, garage infrastructure, and service center infrastructure blanket projects. TURN argues that the Commission should remove these contingency amounts from SCE's capital expenditure blankets, consistent with the outcome adopted in SCE's 2009 and 2012 GRC decisions. TURN recommends reducing SCE's capital forecast by $4.539 million in 2014 and $8.365 million in 2015 for contingency amounts applied by SCE within CRE construction projects and blankets.

In SCE's 2009 GRC, the utility proposed CRE capital expenditure forecasts that included contingency estimates that averaged approximately 15% of the project costs. Despite SCE's arguments that such contingency percentages are standard industry practice and that the proposed percentages varied based on

the level of risk for each project, the Commission concluded that SCE had inadequately substantiated the contingency percentages it applied to its capital projects for CRE.

In SCE's 2012 GRC, the utility again included contingency amounts in its CRE capital project forecasts, this time based on an across-the-board 10% contingency factor. SCE claimed that by reducing the factor and limiting its application to only "hard construction costs, it responded to the Commission's concerns stated in the 2009 GRC, at least as understood by SCE. The Commission disagreed, stating that SCE's cost estimates were at a preliminary stage and not sufficiently reliable to determine that any contingency funding was warranted. The Commission removed the 2012 contingency factor for such construction projects.

TURN argues that in SCE's 2015 GRC, contingency costs should once again be removed from CRE capital forecasts.[787]

SCE responds that TURN's recommendation is solely based on the Commission's 2009 and 2012 GRC decisions rejecting system-wide contingency adjustments, and that TURN cited no other authority rejecting individual contingency percentages developed by SCE on a project by project basis. In recognizing the basis of previous Commission disallowances of single system-wide contingency adjustments, SCE forecast contingency on project-by-project basis incorporating contingency amounts within each project per RS Means industry standards.

As described by SCE's Director of Corporate Real Estate, SCE included no explicit contingency forecast in direct testimony as a blanket and uniform contingency percentage was not applied in generating the forecasts for CRE

[787] TURN OB at 187-188, citing D.09-03-025 at 247 and COL 186 and D.12-11-051 at 568.

capital projects in this GRC. Rather than applying a system-wide and uniform contingency percentage to the CRE projects, SCE (in consultation with professional construction cost-estimator Cumming, Inc.) applied unique contingency percentages based on the nature and scope of the subject CRE project.

SCE's Planning Estimates incorporate contingency adjustments ranging from 8% to 13% for individual projects and 2% to 15% for blanket projects. SCE claims these percentages represent reasonable contingency levels for CRE projects based on project type and phase of planning. Per industry standard, the separate and distinct contingency percentages were applied to each project cost estimate to provide the best indicator of the ultimate costs of the projects. If the contingency percentages applied by SCE to CRE's capital projects are disallowed, SCE believes TURN's proposed contingency-related disallowances must be adjusted to remove disallowances tied to any CRE projects where the Commission accepts TURN's recommendation of zero customer funding for 2014-2015.

TURN's disallowance figures incorporate contingency adjustments totaling $2.476 million (out of $4.549 million) in 2014 and $5.629 million (out of $8.365 million) in 2015 which SCE claims are already accounted for in TURN's recommendations for zero funding on those CRE capital projects. SCE argues that any denial of funding for CRE capital projects forecast during 2014 and 2015 will already remove the respective contingency adjustment for such project.

TURN agrees that disallowed contingency amounts should reflect the project-specific contingency percentages SCE provided in a supplemental discovery response, applied to Commission-approved project cost estimates.

We adopt TURN's recommendation to disallow the contingency amounts that SCE included relating to the CRE projects and for which funding is authorized for 2015. SCE's direct showing did not address whether CRE estimates included a contingency adjustment, much less explain or support the amounts of any such adjustment. Through supplemental discovery, SCE revealed the amounts of design and other contingency in each project forecast, totaling $32.959 million for 2013-2017. SCE attempted to augment its showing by presenting support for its contingency amounts in its rebuttal testimony, but the ALJ issued a ruling striking that testimony.[788] We affirm the ruling of the ALJ.

In hearings, SCE's witness described, in general terms, the process for developing contingency estimates, but this testimony did not discuss project specifics or provide detail to support specific amounts.[789]

Given the absence of adequate record support for SCE's request for contingency amounts and the prior GRC decisions rejecting SCE's request for contingency amounts even where the utility had presented some amount of record support for its request, we conclude that SCE's request to include contingency amounts here should also be rejected.

TURN observes that in the 2012 GRC, we reduced SCE's project management costs due to a lack of support in SCE's showing. TURN contends that SCE's showing in this proceeding is essentially unchanged and provides no more detail, other than an additional comment on precedent. Accordingly, TURN recommends a reduction of 50% or more of SCE's project management costs, which TURN calculates as $12.943 million across various projects. TURN admittedly raises this argument for the first time in its opening brief.[790]

[788] ALJ Kevin Dudney, 11 RT 1218-1219, striking the testimony proffered in Ex. SCE-24V3 at 19, line 7 through at 22, line 2.
[789] 11 RT 1199-1204.
[790] TURN OB at 190-191, citing D.12-11-051 at 569.

SCE responds that its work-papers and discovery materials provided TURN with detailed cost estimates, including project management costs, and that it provided testimony sufficient to demonstrate total project costs were reasonable. SCE notes that the reduction we made in the 2012 GRC was related to SCE's use of a flat percentage of costs, and argues that its estimates here are distinguishable because they are detailed estimates of labor hours. SCE argues TURN could have and should have raised this concern earlier.[791]

While we agree with SCE that TURN could have and should have raised this concern earlier, we also remind SCE that TURN does not bear the burden of proof in this case. As in the 2012 GRC, we find that SCE's direct showing was inadequate to support its full project management request, but decline to disallow the full amount.

We combine these two disallowances (contingency and project management) into a single percentage disallowance that we apply to each project we approve below, including the undisputed projects. The contingency estimates cited by TURN are approximately $12.904 million and project management costs are $12.943 million. Comparing these to the total capital of $271.665 million yields a factor of 9.5%[792]

12.5.5.2. Emergency Operations Center

SCE requests $5 million in 2015 to construct a new 20,000 square foot Emergency Operations Center (EOC) capable of supporting 24 hours, 7 days a week operations and meeting Uniform Building Code standards for "essential facilities" with additional upgrades to provide seismic quake resistance. The EOC will benefit the customers and the community at large through enhanced

[791] SCE RB at 134, citing D.12-11-051 at 569.
[792] TURN OB at 187 and Appendix B at 2, SCE-24V3 at 15.

response to and timely and efficient recovery from emergencies of varying scale.[793]

TURN's recommendation that the Commission reject funding of the EOC relies on two arguments: (1) TURN contends that SCE previously received funding for an emergency operations center in the 2012 GRC; and (2) SCE's construction of an interim emergency operations center at its Gateway facility obviates the need for the EOC. As an alternative, TURN recommends that if we approve the EOC, we should remove the undepreciated portion of the Gateway facility from rate base.[794]

SCE's supporting testimony in the 2012 GRC states that the "emergency operations command center" portion of the Pomona Transportation Services Department (TSD) was never intended to serve the same purpose as the EOC and, instead, was an emergency communications hub solely serving the vehicle fleet. SCE's uncontested testimony also reflects that SCE prioritized the need to mitigate risks from emergency events and disasters by constructing the interim EOC in an existing facility and enhancing its emergency response capabilities temporarily, while a more permanent solution was determined. The interim facility at Gateway has been utilized to respond to several emergency events and to host multiple training exercises, meetings, project planning and other emergency preparedness activities. SCE will continue to use the facility as office space following the EOC's construction. Given the need for a more seismic resistant and advanced facility, SCE argues that it's requested funding for EOC remains a pressing need.[795]

[793] SCE OB at 262-263.
[794] TURN-8 at 15-16.
[795] SCE-24V3 at 30-31 and SCE OB.

In its brief, TURN argues that we delay consideration of EOC until after it is completed and that we require SCE to demonstrate that the interim EOC at Gateway remains used and useful.[796]

We approve SCE's 2015 forecast for the EOC, subject to reductions described elsewhere in this decision. We agree with SCE that the EOC serves an important function separate from the TSD and beyond the intent of the interim EOC. Therefore, we find it reasonable to approve the 2015 portion of the project. However, SCE must apply for the balance of the project in its next GRC. Further, we agree with TURN that SCE has not demonstrated that the interim EOC will remain used and useful after a new EOC is complete. Therefore, SCE must also make a showing in the next GRC that the interim EOC remains used and useful or the undepreciated balance shall be removed from rates.

12.5.5.3. General Office 2 (GO2) Conference & Training Center

After the migration of data center operations from GO2 to the Alhambra Data Center, CRE will repurpose the building into a Conference and Training Center. SCE's 2014-2015 forecast for planning, design, engineering and permitting of this project is $1 million.[797]

TURN recommends no customer funding for the project, arguing that funding be secured through SCE's avoidance of off-site meetings following its construction. TURN estimates this savings as $4.3 to 4.6 million per year. TURN recommends that we require a specific adjustment to account for these O&M savings in the next GRC.[798]

As the Conference and Training Center will not be completed until late 2017, SCE will realize no savings until 2018, which is outside the forecast period

[796] TURN OB at 196-197.
[797] SCE OB at 263.
[798] TURN-8 at 11-13 and TURN OB at 194-195.

for this rate case. A dedicated training and conference space at GO2 will not only reduce off-site meeting expenses, but will reduce time and safety risks associated with employees traveling to distant training and meeting locations.[799]

We agree with TURN that the cost-benefit analysis of this project should be explicitly presented in the next GRC, and require SCE to provide this analysis in its direct showing. However, the merits of the project are essentially uncontested. We find reasonable and approve SCE's 2014-2015 forecast.

12.5.5.4. GO5 Parking Structure

SCE seeks funding of $10.9 million from 2014-2015 to fund the Parking Structure for its General Office Headquarters Building (GO5). SCE claims that construction of the parking structure is needed to ameliorate congestion issues associated with insufficient parking spaces and to maximize use of the facility space. The GO5 will host thousands of employees, candidates, and supplemental workers. SCE claims that it needs to increase the number of existing parking spaces at the GO5 parking lot by 300 spaces to accommodate the volumes of employees, contractors and visitors that frequent the facility.[800]

TURN contends that this funding should be disallowed based upon excessive cost and historic employee occupancy of GO5. TURN argues that these are very expensive parking spaces SCE proposes to build. According to the utility, the price range for parking structures in the Los Angeles area range from $19-$21,000 per space for above-grade structures, and $23-$25,000 per space for subterranean parking structures. The $36,000 effective per-space rate for the 300 spaces SCE would gain from this project is 50-100% above the SCE-reported local market cost.

[799] SCE OB at 264.
[800] SCE OB at 264.

Even if SCE's cost forecast is deemed reasonable for a net gain of 300 parking spaces, TURN argues that we should still deny funding for this project. SCE is presuming one parking space per employee seated at GO5. Rather than build more parking spaces, TURN believes SCE should first encourage alternatives that would reduce this ratio, such as ride sharing, mass transportation, and similar options other than single occupancy vehicles. Similarly, SCE should continue to seek out and take advantage of other facilities to accommodate peak period parking needs, as it has done in the recent past.

TURN argues SCE claims that it already encourages its employees to pursue alternative forms of commuting, but its assumption of needing one space per employee belies less than a full commitment to the success of those efforts. SCE also cites the potential lack of alternative parking options in the future, and the potential additional operating costs if the utility needs to shuttle employees from more remote parking locations to GO5. If the shuttle service helps to avoid a $10.9 million investment in more parking facilities, TURN contends, the utility could splurge on some extraordinarily nice vehicles for the shuttling and still come out far ahead.[801]

SCE claims that TURN fails to account for the heavy volume of visitors to GO5 and the increased employee occupancy in future years, as SCE continues to exit leased facilities and the related safety and operational challenges arising from the substantial deficit of parking spaces. Although SCE has leased overflow parking from a neighboring facility to address the issue in recent years, this lease expired on November 17, 2014 and was not extended.[802]

We agree with TURN that the applicable denominator for the cost-per-space calculation, from ratepayers' perspective, is the net increase in

[801] TURN-8 at 9-11, TURN OB at 193-194.
[802] SCE OB at 264.

parking spaces, not the gross increase. SCE's attempt to ignore a real opportunity cost is unreasonable. Further, while we agree with SCE that it may have an increasing deficit, SCE has not shown that it has adequately explored alternatives to this project that could reduce the deficit at a cost-per-space of less than $36,000, either by reducing need (e.g., telework policies are not even mentioned in SCE's testimony) or increasing supply. SCE's request is denied.

12.5.5.5. IBC Remodel

SCE requests $20 million in 2015 to remodel and reconfigure the IBC into a customer call center in 2015. The move will allow SCE to consolidate its workforce into fewer facilities and complete its planned exit from leased facility space in Monrovia in 2016.[803]

ORA recommends zero funding for the IBC remodel based on the assertion that the project was addressed in SCE's 2012 GRC.[804] The project, however, was not substantially addressed or approved in the 2012 GRC.[805]

TURN also recommends zero funding, claiming that the project will not be used and useful by the end of 2015. Citing SCE's decision to exit only a portion of the leased facility in Rancho Cucamonga, TURN concludes IBC will not be used and useful until 2016.[806]

In rebuttal testimony, SCE explains that the IBC Remodel project will proceed as planned. While SCE's plan to exit all of the Rancho Cucamonga facility has changed since the application was filed, SCE employees from its Long Beach call center and the Environmental Health and Safety group (from the Monrovia facility with an expiring lease) will be relocated to the IBC during the

[803] SCE OB at 264.
[804] ORA-20.
[805] D.12-11-051 at 576.
[806] TURN-8 at 17-18.

4th quarter of 2015. The scope of the IBC Remodel project remains substantially the same.[807]

TURN rejects SCE's response, calculating that the number of employees forecast (in SCE's rebuttal) to move to IBC is 27-30% lower than in SCE's application and that some of these employees do not have the same requirements as call center employees.[808]

We reduce SCE's forecast by 15%, based on the lower forecast number of employees occupying the IBC. We agree with TURN that it is reasonable to expect reduced costs given the change in use (both number and type of employees). However, we also recognize that some portion of the costs are not dependent on these factors. Our adopted forecast balances these considerations.

12.5.5.6. Rancho Cucamonga Office Building Optimization

SCE requests funding of $3.3 million in 2015 for demolition and removal of specialized infrastructure built into the leased facility in Rancho Cucamonga arising from SCE's exit of two out of three floors in 2015. SCE reduced its forecast for the Rancho Cucamonga Office Building Optimization project from $5 million down to $3.3 million based upon the modified plan to exit only two of the three floors formerly occupied. SCE still has a contractual obligation to return the exited portion to the landlord to its pre-lease condition. SCE claims these costs are appropriately capitalized, noting that improvements to the leased space were capitalized. SCE analogizes to T&D salvage operations.[809]

[807] SCE-24V3 at 33-34.
[808] TURN OB at 197-198.
[809] SCE-24V3 at 28-29.

TURN accepts the adjustment to $3.3 million as reasonable. However, TURN recommends that these costs should be expensed over three years rather than capitalized. TURN observes that lease costs are treated as O&M.[810]

We find that TURN's proposed ratemaking treatment to expense these costs over three years is reasonable. This treatment avoids any unintended incentive for SCE to modify and later restore leased facilities in order to inflate rate base. Accordingly, we approve a $0.995 million (2015$) O&M expense, calculated as $1.1 million, adjusted as discussed in Section 12.5.5.1. above. We add this expense as Non-labor in Account 935.

12.5.5.7. Capital Maintenance Program

SCE requests $41.358 million over the 2014-2015 period for the maintenance and renovation requirements of SCE's non-electric facility portfolio (which have an average age of 36 years). SCE claims these expenditures are needed to address facility system and component age obsolescence and to provide a safe and habitable environment for its workforce.[811]

TURN recommends $28.840 million over the 2014-2015 period, a reduction of $12.518 million from SCE's forecast. The primary basis for TURN's recommendation is its contention that SCE is mischaracterizing its facilities as being in "poor" condition based on application of Facility Condition Index (FCI) scores, compared to the way Parsons (an engineering firm) uses FCI. TURN's reduced forecast relied on a six-year average of 2008-2013 recorded costs for Capital Maintenance spending (excluding the highest and lowest years to reduce variation).[812]

[810] TURN OB at 195-196.
[811] SCE OB at 266.
[812] TURN-8 at 20-23.

SCE claims that TURN's forecast understates the amount of capital maintenance needed even to minimally preserve SCE's non-electric facility portfolio without risking safety and compliance impacts. SCE explains that it relied on a separate scale, which it claims is standard and is more stringent than the scale recommended by Parsons. The Parsons' Assessment projects that capital maintenance spending of approximately $47 million per year is necessary to prevent further deterioration of SCE's non-electric portfolio and maintain its existing FCI rating of 19.84 %. SCE's forecast is lower than what Parsons projected as the level of spending needed to maintain the facilities in their current conditions. SCE claims that its forecast of Capital Maintenance forecast represents the minimum level of spending to prevent further, unacceptable deterioration to those facilities.[813]

TURN argues that SCE offers no basis to claim that the Parsons report substantiates a higher forecast. SCE does not describe how it developed the spending projections for any of the categories, or otherwise demonstrate that the projected spending level is reasonable. TURN notes that the Parsons report also stated that "few, if any, inventories of public buildings ever achieve an overall rating of 10% or below." Parsons had routinely found existing average building conditions throughout the United States to fall within the range of 25-35% FCI. SCE's direct testimony refers to a "portfolio FCI score of 22-27%," but the Parsons report indicates a FCI score of 19.84% for SCE's facilities. Any of these scores would place SCE's facilities in the upper range of the "fair" rating under Parsons's recommended standards for SCE, and would indicate SCE's facilities at or better than the top of the range for average building conditions in the United

[813] SCE-24V3 at 35-37.

States. Yet SCE originally chose to present the figures as falling into the "poor" category.

TURN contends that the $47 million per year figure reflects the totality of work that Parsons assumes SCE will need to perform through 2023, and covers all work not only in the most critical categories. TURN notes that this includes "Priority 4" work with its estimate in excess of $300 million over a five-year period that is likely to cover two rate case cycles into the future. TURN also contests the 53% "soft cost" amount included in calculation of the $47 million figure, and concludes that if this were excluded along with lower priority work, the estimate would be far below the $14.42 million per year that TURN recommended.[814]

Both SCE[815] and TURN[816] accuse each other of a selective reading of the Parsons report, and in this regard, both are correct. We agree with TURN that SCE's presentation of the Parsons report in its direct testimony is disingenuous. However, we believe that preventive maintenance is important and are not as quick as TURN to throw out all of the lower priority categories of maintenance identified by Parsons to calculate a no-deterioration maintenance budget. In light of the Parsons report, we conclude that SCE's forecast is reasonable. We note that SCE's proposal is lower than the six-year recorded average, if 2011 and 2013 are included. Further, we apply the adjustment discussed in Section 12.5.5.1 above to this forecast, in light of the soft costs assumed in the Parsons report.

12.5.5.8. Ongoing Furniture Modifications Blanket

SCE requests $5.898 million over 2014-2015 for its Ongoing Furniture Modifications blanket, which provides funding to address normal wear and tear

[814] TURN OB at 200-202.
[815] SCE RB at 131.
[816] TURN OB at 201.

to office furniture and the reconfiguration and modification of furniture and furniture systems for workspaces.[817]

TURN recommends funding $3.038 million over the 2014-2015 period, a reduction of $2.86 million from SCE's forecast. TURN's reductions reflected a six-year average for 2008-2013 recorded spending ($1.688 million), adjusted to reflect the reduced need for furniture modifications in light of SCE's reduced forecast of total and seated employees (a further 10% reduction). TURN calculates that SCE is requesting a 216% to 315% increase in costs on a per-employee basis and concludes that this increase is not justified.[818]

SCE claims that TURN fails to consider SCE's centralization of furniture requests and replacements, as formerly split between CRE and the OUs with large furniture requirements, in March 2013. SCE's forecast represents no increase of total furniture spending over historical costs, but reflects the transfer of the furniture expenditures that formerly resided in other OUs to CRE. TURN's proposed forecast compares CRE's Ongoing Furniture Modifications forecast with pre-centralization historical expenditures. The recorded furniture spend for the elements that are now budgeted in CRE shows furniture spending under this blanket in line with SCE's forecast.[819]

TURN responds that SCE fails to provide the data that might back them up. SCE could have included in its testimony or workpapers the recorded data for 2008-12 for furniture spending that "resided in the OUs" during that period. Such data would permit an apples-to-apples comparison with the utility's 2013 recorded data. SCE did not present the data that might back up its claims. Instead, it mischaracterizes TURN's recommendation as being a reaction to the

[817] SCE OB at 267.
[818] TURN-8 at 24-26.
[819] SCE-24V3 at 40.

perceived increase from the 2013 forecast to the 2014 forecast. TURN's recommendation is based on the recorded amounts as SCE reported them for 2008-2013, and the significant reductions to SCE's work force forecasted for 2015 as compared to the work force during the 2008-13 period.[820]

While we agree with TURN that SCE could have provided more data to "back them up," we find that SCE's explanation of the increase (in uncontested sworn testimony) is logical. Accordingly, SCE's forecast, as adjusted is reasonable.

12.5.5.9. Energy Efficiency Blanket

SCE requests $5.1 million over the 2014-2015 period for its energy management upgrade program, which includes installation of a supplemental chiller and enhanced building management systems to conserve energy usage throughout SCE's non-electric facility portfolio. SCE proposes Energy Efficiency spending of $2.5 million in 2014, and $2.614 million in 2015. The 2014 forecast covers an $800,000 chiller plant for SCE's General Office facility, and $1.7 million for its new Building Management System. The 2015 forecast would be entirely spent on the Building Management System.[821]

TURN recommends denial of SCE's funding requests because SCE's energy efficiency projects, both as pursued in the past and as proposed for this GRC period, are not cost-effective from a ratepayer perspective. In 2010-2011, SCE spent $4.9 million on various water conservation projects at three of its facilities, all recorded under the energy efficiency blanket. The projects achieved water savings, but in the amount of $10,702 per year. TURN calculates an

[820] TURN OB at 203-204.
[821] SCE OB at 198.

average simple payback period of 457 years. TURN recommends that we instate a guideline of a maximum five-year simple payback period.[822]

SCE claims that TURN's reading of SCE's energy efficiency reports are selective. As reflected in SCE's showing, the payback period for SCE's past energy efficiency projects show a more reasonable payback period than TURN's calculation. SCE's proposed projects in this rate case period are for the reduction of energy use during peak usage periods and have a calculated payback period of 7.63 years.[823]

TURN does not disagree with the theory of SCE's calculation, but notes that SCE does not charge itself for electricity and, therefore, payback will never be achieved over any period. TURN states that this is a theoretical payback period, premised on the notion that SCE's facilities pay for electricity they consume. Since the facilities do not actually pay for electricity, there is no actual "payback period" and there is no chance SCE's customers will recoup the costs of the energy efficiency projects through associated energy savings. Therefore, TURN concludes, whatever the benefits of energy efficiency projects installed at SCE facilities, the ratepayer savings from reduced electricity consumption will always be zero.

TURN argues that ratepayers should not fund such projects in GRCs. As capital expenditures, SCE's energy efficiency projects require depreciation, tax and return expenses that are very real. If there were a way to have SCE's customers pay theoretical dollars to cover the costs of achieving these theoretical benefits from SCE's energy efficiency and water conservation activities, continued SCE investment in these programs might make sense. Until that

[822] TURN-8 at 18-20.
[823] SCE-24V3 at 40.

happens, though, TURN argues, ratepayers should not fund such projects through GRC forecasts.[824]

TURN's contention that there are no ratepayer benefits to SCE's energy efficiency improvements because SCE does not charge itself for electricity is wrong. This argument suggests that SCE should never factor utility electricity usage into its decision making, so long as the energy will be supplied by SCE. TURN implicitly asks us to ignore the real costs to generate or procure energy and deliver that energy to SCE's facilities. While we acknowledge the many challenges of measuring avoided costs, we decline to simply ignore these costs that are potentially avoided by energy efficiency. We remind TURN that these are real costs, paid for in real ratepayer dollars.

SCE's forecast 7.63-year forecast payback period for the investments proposed here is uncontested. This is considerably longer than the five-year target proposed by TURN. However, there is no adopted target for payback periods, and we decline to do so here with the limited information before us. Instead, based on our review of SCE's forecast and the benefits of the specific projects here, we find that SCE's forecast is reasonable.

12.5.5.10. Garage Infrastructure Upgrade Program

SCE requests $10.340 million over the 2014-2015 period for its Garage Infrastructure Upgrade Program. The upgrades would cover SCE's 43 garages and maintenance facilities, staffed by approximately 225 employees. Most of SCE's garages are older, and are exposed to consistent and demanding use by large vehicles and equipment. SCE argues that the upgrades are needed to address wear and tear, and for upgrades as equipment and work methods evolve to provide a safe and productive workplace for SCE's employees.[825]

[824] TURN OB at 196-200.
[825] SCE OB at 268.

TURN recommends the Commission deny SCE's entire $10.34 million request. TURN argues that the Commission's review of such a request should take into consideration SCE's admitted "failure to move forward" with the authorized spending from the past GRCs. And under the circumstances here, TURN believes SCE's requested level of funding for its Garage Infrastructure Update Program should be denied because of SCE's track record in the 2009 and 2012 GRCs.[826]

SCE responds that there is no cited authority for barring it from seeking recovery for projects in subsequent rate cases simply due to SCE's failure to move forward with the same or similar projects for which was authorized in prior rate cases. SCE claims it exercised its discretion to re-direct funds to higher priority projects and did not previously move forward with the project. To allay concerns about SCE's plans to move forward with this program, SCE claims that work on portions of the program (including the Ontario Garage) had already commenced, and the current projected spend by year end 2014 is approximately $7 million.[827]

We conclude that SCE has failed to justify ratepayer funding of the entire $10.340 million over the 2014-2015 period for the Garage Infrastructure Upgrade Program. SCE has declined to implement garage infrastructure upgrades that were previously authorized by the Commission. We thus remain skeptical that the full amount that SCE has forecasted would, in fact, actually be spent on the program during the 2014-2015 cycle, rather than being redirected into other purposes deemed by SCE to have higher priority. Nonetheless, since SCE has shown that some actual work on portions of garage upgrades has already at least commenced, SCE may implement at least some level of spending on the garage

[826] TURN-8 at 22-24.
[827] SCE-24V3 at 42.

upgrades during the 2014-2015 cycle. Yet, while SCE estimates spending $10.34 million during 2014-2015, of which $7 million was to occur by year-end 2014, we remain doubtful that SCE will implement funding at the full level requested, particularly based on SCE's past re-prioritization practices. As a way to quantify our caution in this regard, we will approve funding for only $5.17 million, representing 50% of the amount that SCE requests. In this manner, while we provide some funding for a worthwhile program, we mitigate the risks that ratepayers may be charged for funding programs that are not implemented as planned.

While SCE is not barred from seeking recovery for projects for which funding was previously authorized in prior rate cases, SCE must provide a satisfactory justification of why funds that were previously authorized, but not spent for the authorized purpose, should be authorized yet again. Our approval of a reduced budget in this regard reflects our caution in the face of SCE's past spending patterns, while recognizing the importance of implementing the garage infrastructure upgrades over time.

12.5.5.11. Service Center Infrastructure Upgrade

SCE requests $20.679 million over the 2014-2015 period for SCE's Service Center Infrastructure Upgrade program to address operational and asset preservation needs at SCE's Service Centers. SCE claims that severe and pressing needs exist at eight of its Service Centers (including, overcrowded workspaces at Bishop, Kernville, Ridgecrest, San Joaquin, and Fullerton Services Centers and inadequate parking, garage, storage and vehicle circulation space at all of the covered Service Centers).[828]

[828] SCE OB at 268-269.

TURN acknowledges the need to modernize and upgrade the Service Centers, but recommends $3.5 million per year from 2014-2015, representing a $13.62 million reduction of SCE's forecast. TURN's recommendation relies on SCE's request for funding in prior GRCs and challenges SCE's presentation of FCI scores, noting that SCE's direct testimony relied on a preliminary report and that most FCI scores were lower (better) in the final Parsons report. TURN argues that a denial of any funding increase would be appropriate given the track record SCE achieved in the 2009 and 2012 GRCs.[829]

SCE argues that its prior request for funding for projects in past GRCs does not bar a request for funding in future rate cases where the funds were used to cover other, emerging capital needs. SCE argues that failure to move forward with this project will hasten deterioration of the Service Centers and risks the need for higher funding to address repair and replacement costs.[830]

We adopt TURN's recommended reductions in spending based on SCE's past patterns of redirecting funds that were previously authorized.

To address concerns about its commitment to the project, SCE noted that planning and permitting for work at the Bishop, Kernville, Redlands, Ontario, and Ridgecrest Service Centers has already commenced, and currently projects spending approximately $23 million.[831] Nonetheless, based on its past patterns of redirecting approved funding, we question whether SCE will actually spend the entire amount it is requesting. As TURN observes, SCE sought and received in excess of $100 million cumulatively in the 2009 and 2012 GRCs for the same type of work SCE claims is now essential, yet SCE spent zero during the 2009 GRC cycle and $650,000 in 2013.

[829] TURN 8 at 26-28.
[830] SCE-24V3 at 44-46.
[831] SCE-24V3 at 45.

We acknowledge the need to maintain deteriorating service center facilities over time. The average age of the service centers under SCE's program is 51 years old. Both SCE work methods and the surrounding communities have seen significant changes since they were originally constructed. SCE claims the average FCI scores for the designated Service Centers shows them to be in fair to poor condition. We question SCE's claims regarding the condition of its service center facilities, however, given the changes in the reported FCI scores over time. SCE reported "preliminary" FCI scores for eight of its service centers in direct testimony. The final scores for all but one of the eight facilities improved, illustrating that condition of the service centers was better than SCE had originally contended. Using the final FCI scores and the consultant's grading scale, all of the scored service centers are currently in "fair" condition except for Bishop and San Joaquin.

12.5.5.12. IT Equipment & Infrastructure Blanket

SCE requests $5.646 million in 2014 and $7.684 million in 2015 for the IT Infrastructure and Equipment Blanket, which includes equipment such as fiber installations, SONET terminals, router cores, racks, cable and fiber trays, radio/cellular/phone/voice over internet protocol systems. This cost was historically accounted for in previous GRCs as a component within each CRE capital project, and the expenditures remain an essential component to support the efficient use of SCE's non-electric facilities.[832]

Neither ORA nor TURN question the need of the project, but both recommend no funding based on SCE's submission of testimony in April 2014, after the GRC Application was filed. TURN also submits an alternative proposal,

[832] SCE OB at 269-270.

which removes four CRE projects with high IT spend to calculate a modified forecast of $3.257 million in 2014 and $3.213 million in 2015.

As detailed in SCE's data requests and prepared testimony, SCE inadvertently left out references to the telecom portion of project costs in various exhibits, including this project. To address this omission, SCE submitted supplemental testimony to its initial showing as part of Exhibit SCE-14. SCE argues that it submitted the testimony at the earliest feasible date, and did not contravene the Scoping Memo's direction that parties make their case in direct testimony and pleadings rather than in rebuttal or during hearings. During the July 18, 2014 Status Conference, SCE was granted the opportunity to submit additional testimony concerning the telecom projects and ORA and intervenors were granted the opportunity to submit responsive testimony. SCE thus argues that the submission of supporting testimony for this project in April 2014 does not justify denial of funding.[833]

TURN claims, in addition to its procedural objection, that SCE's supplemental exhibit (SCE-14) did not provide adequate justification for these costs. TURN agrees with SCE's basic logic in calculating the IT costs, but recommends that additional IT-oriented projects be excluded from the calculation (SCE excluded the Alhambra Data Center). TURN proposes to exclude four more projects, each with a higher share of IT costs to total costs than Alhambra Data Center. TURN calculates a 10% IT adder in this way, compared to SCE's 12%.[834]

SCE argues that the four CRE projects TURN proposes to exclude from its modified forecast are very similar in scope and size to projects that SCE will carry out in this rate case period and are appropriate to include in the calculation. For

[833] SCE-24V3 at 47, SCE-17.
[834] TURN-8 at 5-8.

example, SCE contends that the interim EOC's IT spend is likely very representative of the permanent EOC which we approve in Section 12.5.5.2 above. Further, SCE already removed (1) the CRE project with the largest volume of IT-related expenditures (the Alhambra Data Center project), (2) CRE blanket programs with little or no projected IT expenditures, and (3) CRE projects under $1 million, from its 2014-2015 forecast to provide the most accurate estimate of IT-related expenditures needed for CRE projects. SCE thus requests that the Commission approve SCE's forecasts of $5.646 million in 2014 and $7.684 million in 2015 for the IT Infrastructure and Equipment Blanket.[835]

We adopt SCE's proposed 12% IT adder, and apply this adder to our adopted, adjusted forecasts for the same projects as SCE. SCE's explanation that the IT spend for the projects it used to calculate the adder are representative of the projects it requests in this GRC is reasonable.

12.5.5.13. Corporate Communications Media Center

SCE seeks to include in its 2014 capital forecast for CRE $1.0 million for a corporate communications media center constructed at its General Office facilities in Rosemead. SCE claims the conversion of existing office space into a media center is necessary to improve SCE's public communications efforts, including emergency response activities. TURN recommends denying rate recovery of such costs, as a new media center for the utility is neither a necessary nor prudent use of ratepayer funds.

SCE claims customer benefits related to timely information, including in the case of actual or potential emergencies and that a dedicated facility to expeditiously generate and disseminate public video communications is needed. This project provides a secure environment to hold and film press conferences

[835] SCE-24V3 at 48-49 and SCE OB at 270-271.

and briefings and mitigates safety and security concerns with the existing publicly accessible site exposed to varying levels of street traffic and weather and lighting conditions. The project has completed the planning and permitting phase and is under construction and slated for completion in 2015.[836]

TURN claims that SCE failed to demonstrate that a new media center is necessary to providing electric service or some other clear benefit to its customers. TURN notes that SCE has not held many press conferences in recent years, ranging from one in 2010 to eleven in 2011 and that SCE does not track attendance. TURN also observes that in some instances, SCE communicates with the press at the site of an event (e.g., outage). Furthermore, TURN claims, SCE has not demonstrated that its media or public outreach efforts in recent years have unduly suffered due to the absence of such a media center.[837]

SCE contends the media center is needed because currently press conferences are held on sidewalks and there is increased demand for faster communication.[838]

We find that SCE has not justified this expenditure. We agree with SCE's premise that timely communications with customers and the public is increasingly important; however SCE presents no evidence that video communications are specifically necessary in lieu of simpler forms, e.g., written communications. Further, as TURN points out, SCE simply has not demonstrated that it needs to hold enough press conferences to justify this expenditure. We reject SCE's request.

[836] SCE-24V3 at 22, SCE OB at 271.
[837] TURN-8 at 8-9.
[838] SCE-24V3 at 23.

13. External Relations

External relations includes several departments and a variety of activities. Our adopted forecast is summarized below (millions of 2012$).

Department	Activity	Account(s)		SCE	Adopted
Corporate Communications	A&G	920/921	Total	$ 7.543	$ 7.314
			Labor	$ 5.739	$ 5.565
			Non-Labor	$ 1.804	$ 1.749
	Measurement and Ethnic Media Services	923	Non-Labor	$ 0.847	$ 0.847
	Communications Products	930	Non-Labor	$ 11.269	$ 7.339
Corporate Membership Dues and Fees		930.2	Non-Labor	$ 1.796	$ 1.177
Integrated Planning & Environmental Affairs	Integrated Planning	557	Total	$ 6.227	$ 6.227
			Labor	$ 5.244	$ 5.244
			Non-Labor	$ 0.983	$ 0.983
	Generation Planning	549	Total	$ 6.303	$ 3.909
			Labor	$ 1.320	$ 1.320
			Non-Labor	$ 4.983	$ 2.589
	A&G	920/921	Total	$ 2.990	$ 2.971
			Labor	$ 1.840	$ 1.840
			Non-Labor	$ 1.150	$ 1.131
Regulatory Operations and RP&A		920/921	Total	$ 16.283	$ 16.283
			Labor	$ 14.139	$ 14.139
			Non-Labor	$ 2.144	$ 2.144
Local Public Affairs	A&G	920/921	Total	$ 13.207	$ 12.784
			Labor	$ 11.072	$ 10.957
			Non-Labor	$ 2.135	$ 1.827
	Business License Tax	408	Non-Labor	$ 0.585	$ 0.575
Transportation Electrification		588	Total	$ 5.595	$ 5.595
Total				$ 72.645	$ 65.021

13.1. Corporate Communications

SCE contends that providing timely information to customers and other stakeholders is critical. Further, its Public Safety Around Electricity Campaign is an important initiative that has successfully increased awareness.

ORA generally contends that SCE's requested increase is too large (94.1%) relative to 2012 recorded, duplicative of other programs, uncoordinated, and not limited to programs with ratepayer benefits. ORA proposes a smaller (39.6%) increase.[839]

13.1.1. Administrative and General (A&G) (Account 920/921)

SCE forecasts $7.543 million of TY 2012 expenses in Account 920/921 for its Corporate Communications Department, which is $1.311 million less than 2012 recorded levels. SCE's forecast was developed by removing $0.715 million in OpX savings and $0.910 million for the permanent shutdown of SONGS from the 2012 recorded amount, and adding incremental labor and non-labor expenses of: (a) $0.229 million to support the Summer Readiness Energy Conservation Campaign and the Public Safety Around Electricity Campaign; and (b) $0.230 million for social media management tools.[840]

ORA forecasts $4.871 million for this account, a $2.672 million reduction, based on using "the total authorized level of $13,928,000 from TY 2012 and reallocating it using relative shares of SCE's 2013 subaccount forecasts." ORA argues that SCE spent less than authorized in 2012 and that SCE's forecast may not be reliable.[841]

SCE claims that ORA's recommendation is unreasonable, as it does not take into account SCE's recorded dollars in each of the FERC Accounts or any TY

[839] ORA-21 at 6.
[840] SCE-25 at 2.
[841] ORA-21 at 7-8.

2015 adjustments SCE made in each of the accounts. ORA does not explain why it used SCE's 2012 authorized amount and how it re-allocated the amount to various FERC accounts. SCE contends its method follows Commission precedent.[842]

ORA responds that it is SCE's method that is unreasonable, as it relies on older, generic Commission decisions, rather than on the most recent decision in SCE's TY 2012 GRC. In its decision in SCE's last GRC, ORA argues, the Commission expressed concern that SCE had not used effectively the ratepayer funding it already received when confronted with the 2011 Windstorm.[843]

To develop its forecast, SCE claims it followed Commission guidance on forecasting methodology and described why it chose a certain forecasting methodology in each of the accounts. SCE's labor forecast in FERC Account 920/921, for example, is less than all recorded years since 2008.[844]

We find SCE's approach of using 2012 recorded as a baseline reasonable because it is consistent with our past guidance. We review SCE's proposed adjustments as follows: OpX is reasonable and discussed in Section 27 below, the SONGS adjustment is uncontested and is reasonable, we deny the expenses associated with the advertising campaigns (see Section 13.1.3 below), and we approve the uncontested social media management expenses. Our adopted forecast is $7.314 million (2012$).

13.1.2. Communication Measurement and Ethnic Media Services (Account 923)

SCE forecasts $0.847 million for FERC Account 923 for communication measurement and ethnic media services. SCE's forecast is uncontested, reasonable, and approved.

[842] SCE-25 at 3.
[843] ORA OB at 341.
[844] SCE OB at 273.

13.1.3. Communications Products (Account 930)

SCE forecasts $11.269 million for TY 2015 expenses in FERC Account 930 based on a 5YA ($0.698 million) and the following incremental expenses: (a) $8.210 million to conduct the new Public Safety Around Electricity Education Campaign, (b) $2.331 million for the new Summer Readiness Energy Conservation Campaign, and (c) $0.030 million for SCE's Corporate Responsibility Report.[845]

ORA's forecast for this account is $6.220 million, a reduction of $5.049 million. TURN's forecast is $7.067 million for this account, a reduction of $4.202 million. [846] As noted above, ORA bases its forecast on 2012 authorized reallocated based on 2013 forecast.[847]

We adopt TURN's forecast for this account, except for the baseline amount, for a total forecast of $7.339 million, as discussed and summarized below (millions of 2012$).

	SCE	Adopted
Baseline	$ 0.698	$ 0.698
Public Safety Around Electricity	$ 8.210	$ 6.641
Summer Readiness	$ 2.331	$ -
Corporate Responsibility Report	$ 0.030	$ -
Total	$ 11.269	$ 7.339

13.1.3.1. Baseline

TURN recommends a baseline based on 2012 recorded, due to a claimed steady decline in costs and to account for a recent reorganization. TURN views the variation as driven by the safety education component, while the annual

[845] SCE-9 at 23.
[846] SCE OB at 274.
[847] ORA-21.

report costs have been declining. The reorganization moved some costs to the Customer Service OU.[848]

SCE responds that there is no double counting due to the reorganization – this has been corrected in adjustments to recorded costs. SCE claims that the 5YA is appropriate because costs have fluctuated, with a relatively high cost in 2010. SCE notes that annual report is only a third of the account, and should not be an overriding consideration.[849]

We agree with SCE that a 5YA is a reasonable baseline. SCE's explanation of the adjustments due to reorganization is reasonable, and the education expenses outweigh the decline in annual report costs.

13.1.3.2. Public Safety Around Electricity Education Campaign

SCE has been producing advertisements on this theme since 2008 in its general advertising activities, funded by shareholders. SCE is increasing the focus of this campaign on safety and advertisements directed toward ratepayers. This is the first GRC that SCE has made this request. SCE claims this campaign had significant impacts on awareness during 2012. SCE cites its 1974 GRC (D.86794, page 51) as precedent that safety advertising may be included in rates.[850]

ORA opposes funding of this Campaign for a few reasons. First, claiming that the Campaign was fully funded in SCE's 2012 GRC. ORA also argues that this program is myopic and inconsistent with the "routine advance planning"

[848] TURN-5 at 75-76.
[849] SCE-25 at 5-6.
[850] SCE-9 at 23-25.

approach discussed in the 2012 GRC.[851] Finally, ORA appears to suggest that this campaign is "institutional advertising," appropriately funded by shareholders.[852]

SCE argues that the Public Safety Around Electricity Education Campaign is targeted toward safety and not improving corporate image, although enhancing its reputation and image may be an indirect result of the campaign. Its primary objective and the success measure is purely related to increasing customer awareness of how to be safe around electricity. SCE provided testimony and workpapers with various examples of safety advertisements produced as a result of this Campaign.

SCE denies that its safety programs are driven by a single event. For example, SCE's public safety education programs, including the electric safety for tree-trimmers, have been around for years. The Public Safety Around Electricity Education Campaign was implemented before the 2011 windstorm occurred. A series of events, including third-party contacts with power lines, led SCE to focus on providing safety messages to the public.[853]

TURN recommends a reduction of $1.569 million for SCE's Public Safety Around Electricity Education Campaign. TURN recommends the use of 2012 recorded costs amount which is $6.641 million.

TURN claims that SCE has not clearly identified a rationale for forecasting significant cost increases in this program beyond the 2012 level, when it evolved into its current form as a "comprehensive, mass-market campaign for residential and business customers with attention paid to both general and ethnic audiences." In 2012, SCE seems to have performed all of the same kinds of activities that it forecasts for the test year, according to TURN. SCE developed

[851] D.12-11-051 at 319.
[852] ORA-21 at 6-10.
[853] SCE-25 at 10, SCE OB at 277.

new safety ads, conducted customer research and focus groups to test new ads, and bought media placement. SCE indicates that it plans to expand the use of in-language advertising to reach and interact more effectively with its diverse customer base, such as by adding more Asian in language media buys in 2013 and reaching into more rural areas. TURN submits that these efforts will likely increase costs for media buys relative to 2012 in the test year, according to SCE, while at the same time, creative and production costs will be lower in 2015 than in 2012. SCE intends to incur the creative and production costs of new safety ads only every other year, in 2014 and 2016, but not in 2015. TURN recommends reducing the forecast for this program claiming that SCE offers insufficient identifiable outcomes (i.e., likelihood of fewer safety issues) for spending $8.2 million in 2015, which is more than a 23% increase over the 2012 spending level.[854]

SCE claims that TURN erroneously assumes that "[in] 2012-2013, Edison seems to have performed all of the same kinds of activities that it forecasts for the test year" and that SCE's new media buys "offer no identifiable outcomes (i.e., likelihood of fewer safety issues) for spending $8.2 million on this program."

SCE claims that TURN ignores new work needed in 2014 and 2015 to continue this Public Safety Advertisement Campaign, including new media buys to reach more customers and special audiences (seniors, low-income and the disabled) and to prevent the wear-out factor. SCE was able to increase public awareness from 34 to 47 percent from 2011-2012.

SCE opposes TURN's request for proof that dollars spent on this campaign would lead to a "likelihood of fewer safety issues." SCE argues that many safety-related programs are not suited for cost-benefit analysis, as it is impossible

[854] TURN-5 and TURN-5A at 76-77; TURN OB at 207-208.

to track safety-related incidents yet to occur or to quantify actual and direct benefits.[855]

We adopt TURN's recommendation to reduce the forecast for this program by $1.569 million, and thereby limit ratepayer funding to 2012 levels of $6.641 million. SCE has demonstrated significant progress at current funding levels, and has not clearly identified marginal ratepayer benefits from further funding.

13.1.3.3. Summer Readiness Energy Conservation Advertising Campaign

SCE claims this program was motivated by concern about energy shortages during the summer of 2012 and was launched that April. It achieved 447 million impressions in 2012 of messages on how and why to save energy. This is the first time it has been included in a GRC request. SCE claims its costs are recoverable in rates as "specific conservation advertising." SCE's $2.331 million forecast is based on 2012 recorded.[856]

ORA opposes ratepayer funding of this program as duplicative of other Demand Response (DR) programs.[857] TURN agrees.[858]

SCE disputes the claim that that the Summer Readiness Energy Conservation Campaign duplicates existing DR programs. The DR advertising focuses on enrollment in specific conservation programs, such as the Summer Discount Plan, while the Summer Readiness Energy Conservation Campaign focuses on a broader effort with a long-term goal of affecting attitudes and behaviors of customers around energy conservation, particularly during hot summer months. The Commission has allowed these specific energy conservation advertising expenses to be recovered in rates. SCE claims that its

[855] SCE OB.
[856] SCE-9 at 28-30.
[857] ORA-21 at 8.
[858] TURN-5 at 73-74.

Summer Readiness Energy Conservation Campaign provides "specific, useful information about energy conservation" and "can be of great use to individual customers and can reduce costs for the system as a whole."[859]

ORA notes that SCE underspent its Corporate Communications authorization in 2012, implying that ratepayers effectively funded this campaign in that year, not shareholders. Further, ORA contends that SCE misses the relevance of DR programs to a conservation program like Summer Readiness. ORA claims that this campaign duplicates goals of emergency alerts issued by the California Independent System Operator. Finally, ORA notes that SCE's direct testimony listed one of the goals of the campaign as increasing enrollment in DR programs.[860]

We agree with ORA and TURN that SCE has not demonstrated that this campaign complements rather than duplicates other programs. In particular, we note that the goals include increasing DR enrollment. Therefore, we exclude it from our forecast for Account 930.

13.1.3.4. Corporate Responsibility Report

SCE proposes to add $0.030 million for this report to explain actions on safety, environment, and ethics.[861] ORA claims the report is "institutional advertising" and should not be funded in rates.[862] TURN agrees.[863] SCE responds that the report provides important information to customers.[864] We agree with TURN and ORA and exclude this cost from our forecast.

[859] SCE-25 at 13.
[860] ORA OB at 342-344, citing SCE-9 at 28.
[861] SCE-9 at 30.
[862] ORA-21 at 9.
[863] TURN-5 at 77.
[864] SCE-25 at 14.

13.2. Corporate Membership Dues & Fees (Account 930.2)

SCE is requesting $1.796 million for Corporate Membership Dues and Fees in Account 930.2, based on 2012 recorded expenses.[865] ORA stipulates to SCE's forecast.[866]

TURN proposed an adjustment of $1.745 million to charge shareholders, rather than ratepayers, for dues that TURN claims are political in nature and thus inappropriately assigned to ratepayers. SCE has revised its forecast for External Relations – Account 930 downward by $220,000 after accepting two of TURN's five adjustments, removing all expenses for the California Foundation on the Environment and the Economy ($90,000) and the Business Roundtable ($129,800). Thus, the remaining membership dues contested by TURN is $1.619 million for dues and memberships. TURN contends that other politically oriented dues and donations are contained in the CEO's office and environmental areas.[867]

Three issues remain in dispute between TURN and SCE: dues and/or donations paid to (1) Edison Electric Institute (EEI), (2) CCEEB, and (3) the Civil Justice Association of California.

SCE's forecast includes $1.462 million in Account 930 for EEI corporate membership dues, which reflects a reduction from the full amount of dues of $1.922 million. SCE claims this reduction removes dues identified by EEI associated with Lobbying, Public and Media Relations, Advertising, and Marketing, using the National Association of Regulatory Utility Commissioners (NARUC) definitions for these activities.

TURN recommends additional disallowances. First, TURN claims that SCE has not removed all of the NARUC categories that the Commission

[865] SCE OB at 278.
[866] ORA-57R.
[867] TURN OB at 210.

previously identified as inappropriate for ratepayer funding because of their inherently political nature. Second, TURN claims that EEI recently waged an aggressive campaign in Arizona against net energy metering for distributed solar photovoltaic energy (solar PV), and SCE has not demonstrated that EEI dues to be recovered from California ratepayers exclude these or similar activities.

Since 2013, EEI has undertaken several activities in support of this campaign. TURN argues that if SCE is willing to fund EEI's efforts to fend off distributed PV through intervention in out-of-state utility regulatory proceedings and television advertising (including prime spots like during NFL games), then SCE's shareholders alone should fund those activities.

SCE claims that the evidence TURN uses to support its argument that EEI embarked on a political advertisement campaign in Arizona consists of advertising materials or newspaper articles. SCE claims there is no evidence that the invoices produced by EEI on its advertising expenses are false or that California customer dollars were used in a campaign in Arizona. While EEI did run a TV ad in Arizona, SCE claims the ad was in limited markets for a limited time.

The percentage of dues used for Lobbying, Public and Media Relations, Advertising, and Marketing was 20.5% in 2013, less than the 21.2% in 2012. Based on Commission feedback from SCE's 2012 GRC, SCE took steps in this GRC to obtain documentation from EEI to determine an appropriate shareholder-versus-ratepayer split of EEI member dues. SCE claims that its forecast accurately accounts for the percentage of dues to EEI applicable to lobbying and other expenses that should be funded by shareholders.

In D.14-08-032, in PG&E's 2014 GRC, we adopted TURN's methodology for calculating an EEI disallowance, which removed costs in the following

NARUC categories: Legislative Advocacy, Legislative Policy Research, Regulatory Advocacy, Advertising, Marketing, and Public Relations. As explained in D.14-08-032, "We conclude that TURN's analysis and proposed allocation reasonably reflects the categories of disallowable EEI dues that offer no ratepayer benefits." The full list of NARUC cost categories includes the following: (1) Legislative Advocacy, (2) Legislative Policy Research, (3) Regulatory Advocacy, (4) Regulatory Policy Research, (5) Advertising, (6) Marketing, (7) Utility Operations and Engineering, (8) Finance, Legal, Planning, and Customer Service, (9) Public Relations, (10) General and Administrative, and (11) Overhead.

SCE claims that the "methodology adopted by the Commission in D.14-08-032 is the same methodology followed by SCE in its TY 2015 forecast." SCE removed costs labeled: "Lobbying," plus "Advertising, Marketing, and Public and Media Relations." SCE's claim that it followed the Commission's holding in D.14-08-032 can only be true if the category of "Lobbying" includes the following three NARUC categories, all of which the Commission excluded: (1) Legislative Advocacy, (2) Legislative Policy Research, and (3) Regulatory Advocacy. SCE has not demonstrated that this is in fact the case.

While the definitions of the NARUC category "Legislative Advocacy" and the "Lobbying" category excluded by SCE are not precisely identical, they are similar, creating a strong presumption that SCE's "Lobbying" category is equivalent to the NARUC "Legislative Advocacy" category. In contrast, the NARUC category "Legislative Policy Research" is wholly distinct; "This account … shall not include costs for legislative advocacy." "Regulatory Advocacy" is also clearly distinguishable from the activities subsumed in the meaning of "Lobbying."

TURN contends that that SCE has partially followed the Commission's methodology in D.14-08-032, but not entirely. SCE did not remove two of the NARUC categories excluded in D14-08-032: "Legislative Policy Research" and "Regulatory Advocacy."

We agree with TURN that SCE has not shown that it has removed all political or lobbying costs from its forecast. However, we decline to follow TURN's recommendation to deny recovery of EEI dues outright. SCE ratepayers do receive some valuable benefits through EEI, including information and mutual assistance. Accordingly, we reduce SCE's forecast to $1.000 million to account for these benefits without unnecessarily contributing to EEI political activities.

TURN also contests SCE's dues to the California Council for Environmental and Economic Balance (CCEEB) ($0.117 million) and Civil Justice Association of California ($0.040). TURN contends that both of these organizations are involved in political and/or lobbying activities. We disallowed costs for CCEEB in PG&E's most recent GRC[868] and do so again here. SCE does not contest TURN's characterization of the Civil Justice Association of California. Accordingly, we reject funding for both organizations. Our total forecast for Account 930.2 is $1.177 million.

13.3. Integrated Planning & Environmental Affairs (IP&EA)

IP&EA was formed in 2012 to promote reliable and sustainable electric infrastructure. SCE forecasts $10.654 million for labor expenses and $10.461 million for non-labor.[869]

[868] D.14-08-032 at 566.
[869] SCE-9.

13.3.1. Account 557

For TY 2015, SCE estimates a total of $6.227 million for groups in Integrated Planning that record labor and non-labor expenses to FERC Account 557. ORA recommends no reduction to this account, and TURN's arguments related to name and logo are addressed in Section 28 below. SCE's forecast is adopted.

13.3.2. Generation Planning (Account 549)

SCE forecasts $6.303 million for FERC Account 549 in TY 2015 to fund currently authorized Generation Planning activities. ORA recommends $1.627 million for SCE's non-labor expense, a reduction of $3.356 million.[870]

SCE forecasts activities including: finding locations for generation, technology evaluation, tracking initiatives, etc. SCE's labor forecast is based on 2012 recorded, based on subtracting forecast labor from total 2012 authorized.

SCE proposes to continue recording non-labor costs related to the PDD in the Project Development Division Memorandum Account (PDDMA) for later reasonableness review in an ERRA proceeding. SCE proposes to include labor costs in rates through this GRC, and track only non-labor costs in PDDMA.[871]

ORA accepts SCE's labor forecast, but contends SCE's non-labor forecast is unreasonable and does not reflect current balances authorized for rate recovery. ORA's forecast is based on 2012 recorded.[872]

SCE disputes ORA's argument that "this account should not contain unaudited amounts from previous test years without SCE showing that tracked expenses are associated only with authorized support functions." The non-labor expenses are reviewed in the annual ERRA review proceedings, which consist of

[870] SCE OB at 279.
[871] SCE-9 at 58-61.
[872] ORA-21 at 12-13.

an audit performed by ORA, to verify that Generation Planning's non-labor expenses are only for authorized support functions as directed by the Commission. Because the non-labor expenses remain in a PDDMA memorandum account, the customers will only pay for actually incurred expenses which are subject to the reasonableness review in ERRA. SCE is using the same forecasting methodology for this FERC Account, which has been approved by the Commission for several rate cases, that is, the TY 2015 forecast was based on escalating the TY 2012 authorized amount.[873]

While we agree with SCE that the ERRA process mitigates the risk to ratepayers in this area, we also agree with ORA that it is reasonable to undertake a periodic review of the amount, notwithstanding its review in the PDDMA. SCE's recorded data shows that it has not approached SCE's forecast level in any year in the recorded period, either for the total or non-labor specifically. SCE's analysis does not support an increase in non-labor costs at this time. Non-labor expenses have fluctuated over the five recorded years, and we adopt a 5YA of $2.589 million for non-labor. We adopt SCE's uncontested labor forecast and request to modify PDDMA.

13.3.3. A&G (Accounts 9210/921)

SCE forecasts $2.990 million for IP&EA FERC Account 920/921. ORA does not contest SCE's forecast in this FERC account. TURN recommends disallowing dues paid by SCE to the CCEEB of $0.019 million from SCE's non-labor expense forecast. As discussed in Section 13.2 above, we adopt TURN's related proposed related reduction and also adopt this small reduction. The remainder of SCE's forecast is uncontested and is approved.

[873] SCE-25 at 24.

13.4. Regulatory Operations and Regulatory Policy & Affairs (RP&A) (Account 920/921)

SCE forecasts $16.283 million of TY 2015 expenses for its Regulatory Operations and Regulatory Policy and Affairs Department (RP&A) in FERC Accounts 920/921, an increase of $0.993 million over 2012 recorded-adjusted levels. The increase is primarily due to increased staffing required to meet the growth in NERC regulatory compliance activities and regulatory activities in RP&A. RP&A's labor forecast of $14.139 million includes the addition of five new positions added in the NERC Compliance group and 3 new positions added in RP&A. RP&A also forecast $2.144 million for non-labor expenses associated with the eight new incremental positions.[874]

ORA accepts SCE's forecasts for Regulatory Operations and RP&A's labor and non-labor expenses for TY 2015.[875]

TURN originally recommended a forecast of $14.823 million, a reduction of $1.638 million to SCE's request. However, upon review of SCE's rebuttal testimony, TURN now recommends $16.155 million, proposing that the Commission make two more modest adjustments than TURN originally proposed, totaling $306,000.

First, TURN contends that a 5YA base for non-labor inappropriately includes non-recurring costs from early NERC compliance efforts that are now done by SCE staff. TURN argues that consistency between the labor and non-labor forecasts would eliminate the double counting it sees. TURN recommends a 3YA for non-labor.

[874] SCE OB at 280-281.
[875] ORA-57R.

Second, TURN proposes to adjust the labor forecast based on the new employees actually hired in 2013 rather than the forecast.[876] SCE explains that this second reduction is included in SCE's rebuttal forecast.[877]

Thus SCE's revised labor forecast is undisputed, and we find it reasonable. TURN's first recommendation does not consider or respond to SCE's explanation that there were not non-recurring costs in the first years of the recorded period. Instead, SCE explains, these apparent costs were the result of an accounting change and actually represent normal costs, not one-time NERC costs.[878] SCE's explanation is reasonable, and we find SCE's non-labor forecast reasonable.

13.5. Local Public Affairs (LPA)

13.5.1. A&G (Accounts 920/921)

For TY 2015, SCE forecasts $13.207 million for LPA, an increase of $0.836 million over 2012 recorded and adjusted amount. The increase is primarily due to filling four vacant positions and adding four additional positions in LPA to support the increased workload relating to public safety education, emergency readiness and response, and infrastructure replacement.[879]

ORA agrees with SCE's forecast for LPA.[880]

TURN makes three recommendations: 1) assign a higher portion of costs to shareholders, 2) reject the labor increase associated with staffing increases, and 3) base non-labor on a 2012-2013 average. SCE partially accepted TURN's first recommendation in rebuttal.[881]

[876] TURN OB at 221-222.
[877] SCE RB at 142, citing SCE-25 at 32.
[878] SCE-25 at 31-32.
[879] SCE OB at 282-283.
[880] ORA-57.
[881] TURN OB at 222-223.

SCE has accepted TURN's recommendation to share some overhead costs (e.g. vacation, supervision) between ratepayers and employees, but does not accept TURN's recommendation that training should be shared. SCE contends that its time-tracking study is consistent with our direction in the 2006 GRC. SCE claims that training time is "mandated by corporate policy, training for emergency readiness, and training about the transmission and distribution system." SCE cites a variety of examples of trainings and argues that these trainings are essential for safety, emergency preparedness, and the ability to communicate effectively with customers and stakeholders, and thus, should be ratepayer funded.

Further, SCE explains that non-labor expenses are booked directly to shareholder or ratepayer accounts, depending on the activity. Therefore, SCE argues TURN's proposal to apply a percentage from the labor forecast to allocate non-labor costs to shareholders is unreasonable.[882]

TURN argues that, according to the time-tracking study, LPA staff spend approximately one day per week in training and one day per week on shareholder activities, on average. TURN submits that it is unreasonable to conclude that none of this training supports the shareholder activities. Further, TURN cites some of the topics addressed in training that, it contends, may support shareholder activities.

For non-labor expenses, TURN expresses doubt that SCE's approach is "clear-cut and equitable" and recommends we split the difference between TURN and SCE's original positions, a $0.308 million reduction.[883]

We agree with TURN that SCE's contention that all training is related to ratepayer benefits to the point that shareholders should not share the costs

[882] SCE-25 at 37-39.
[883] TURN OB at 224-225.

strains credulity, given the portions of time revealed in the study. Further, at face value many of the topics can reasonably benefit shareholder activities as well as ratepayer activities. SCE provides a reasonable calculation of these type of general skill building trainings.[884] Accordingly, we adopt an additional allocation of training costs among shareholders and ratepayers according to SCE's method. Further, we adopt TURN's proposed $0.308 million reduction to non-labor expenses on the grounds that SCE has not met its burden of proof that its approach is reasonable.

Next we address the proposed staffing increases. SCE contends that TURN ignores the fact that it did actually fill the eight incremental positions in 2013 and that this increase is based on a need to support infrastructure projects.[885] TURN responds that 2013 labor costs, including these new positions, is below SCE's forecast and contends this supports TURN's lower forecast.[886] We disagree. TURN has not considered the full year cost impacts of these new positions or substantively disputed the need for the positions. SCE's gross labor forecast is reasonable.

Finally, we address the non-labor forecast. SCE argues that 2013 unadjusted data should not be used, and therefore TURN's forecast is unreasonable.[887] TURN argues that any outstanding adjustments are not necessarily upward adjustments and may be de-minimis.[888] We agree with SCE that there has been a trend in recorded expenses and that therefore a gross forecast based on LRY is reasonable.

[884] SCE RB at 144-145.
[885] SCE-25 at 35-36.
[886] TURN OB at 225-226.
[887] SCE-25A at 40.
[888] TURN OB at 227.

13.5.2. Business License Tax (BLT) (Account 408)

SCE forecasts $585,000 in BLT for TY 2015, a 5% annual increase over the amount paid in 2012.[889] ORA did not recommend any reductions.

TURN recommends a $24,000 reduction claiming that SCE's 5% growth rate is unsupported. TURN calculates a 2.78% growth rate; TURN claims new BLT fees have also grown by about 3%.[890]

SCE contends TURN's recommended reduction of $24,000 to the BLT forecast failed to recognize new jurisdictions that added BLTs and omitted $64,352 of new and recurring BLT payments from seven jurisdictions in 2013.[891]

We agree with TURN that SCE has not shown its 5% growth rate to be reasonable, but also accept SCE's point that other cities may begin to charge BLTs. Accordingly, we adopt a forecast of $0.575 million.

13.6. Other Uncontested Issues

SCE's forecast also includes a forecast of uncontested expenses for transportation electrification These uncontested forecasts are approved.

14. Ratemaking

In this Section, we address certain ratemaking proposals that are not addressed elsewhere.

14.1. Market Redesign and Technology Upgrade Memorandum Account (MRTUMA)

Resolution E-4087 authorized the MRTUMA. SCE proposes to recover its 2013 and 2014 capital forecast in this account, and then close the MRTUMA. Earlier capital expenditures were reviewed in A.13-04-001.[892] O&M expenditures are approved in Section 6.1 above. ORA proposes reductions to SCE's capital

[889] SCE OB at 284.
[890] TURN-5 at 227.
[891] SCE-25 at 41.
[892] SCE-10V1R1 at 33-34.

forecast based on the fact that those costs are recorded to this account.[893] ORA misunderstands the relation between ERRA and this proceeding.[894] The ERRA review ensures that the entries in MRTUMA are correct and consistent with other Decisions; the GRC decision reviews and potentially approves the capital forecast. SCE's forecast and request to eliminate the MRTUMA are approved.

14.2. Residential Service Disconnection Memorandum Account (RSDMA)

ORA and SCE agree that the Commission should extend the RSDMA through 2017 to record and track all costs associated with the new practices resulting from R.10-02-005 and D.14-06-036.[895] SCE states its intent to calculate the final recorded 2014 uncollectible expense attributable to the Residential Disconnection OIR and update the RSDMA in early 2015. SCE requests to recover the final December 31, 2014 balance of RSDMA in rates by transferring that balance to BRRBA for recovery through distribution rates. This transfer would be implemented by the advice letter implementing this GRC decision. SCE expects the final 2014 balance to be $17.775 million (nominal$), and provides support for this forecast.[896] No party contests SCE's requests, and we find that they are reasonable and are approved.

14.3. Edison SmartConnect Accounts

SCE proposes to eliminate the Edison SmartConnect Balancing Account (ESCBA) and Edison SmartConnect Opt-Out Memorandum Account (SOMA).[897] No party contests these changes. Recovery of costs recorded in these accounts is

[893] ORA-14 at 52-54.
[894] SCE-26V1 at 7.
[895] SCE-73 at 11, ORA-13 at 50.
[896] SCE-73 at 11-16.
[897] SCE-10V1R1 at 37-39.

addressed in Section 8 above and in other proceedings. SCE's request to eliminate these accounts is approved.

15. Jurisdictional Issues

SCE presents a method for developing factors to allocate total company costs between CPUC and FERC jurisdiction based on D.04-07-022. SCE's method was accepted in D.12-11-051. SCE applies the resulting jurisdictional factors to total system base-related revenue requirements for each year (2015-2017).[898] ORA accepts the method and resulting factors.[899] SCE notes that two other ORA witnesses make recommendations to reduce forecast costs on the basis of jurisdiction and rebuts these arguments.[900] We adopt SCE's uncontested jurisdictional allocation factors and address ORA's specific proposed adjustments in context of those issues.

16. Sales and Customer Forecast

SCE makes three separate but related forecasts: retail electricity sales, customer accounts, and new meter connections; each of these forecasts is composed of customer type or geographic subcategories. SCE, ORA, and TURN each use econometric regression modeling techniques for these forecasts. The most significant disagreement between the parties on this topic is the appropriate method for forecasting new meter connections with SCE and TURN proposing polynomial distributed lag (PDL) models and ORA proposing an Autoregressive Integrated Moving Average (ARIMA) model. The primary explanatory variable in the PDL models is housing starts, lagged from one to twelve months before the month of the forecast.[901]

[898] SCE-10V1R1 at 15-25. SCE reports the factors by FERC Account at SCE-10V1R1 at 21.
[899] ORA-2 at 8-9.
[900] SCE-26V1 at 30-33.
[901] SCE-10 V1R1 at 53, SCE-26 V1 at 34-36, SCE-66 at 1.

ORA criticizes SCE's PDL model on the basis that its residual errors were not likely to be random, white noise. ORA argues that the residuals of its ARIMA model is much more likely to be the result of white noise, and that, therefore, its model is more valid.[902] SCE rejects ORA's model, arguing that: ORA's model does not rely heavily enough on housing starts or maintain the "intuitive" relation with that independent variable, that ARIMA is inappropriate for long term forecasting, and that random residuals do not necessarily show that one model is better than another.[903] ORA claims that its model is valid and is appropriate for forecasting the timespans involved by distinguishing its model from the univariate models discussed in a textbook (Exhibit ORA-58) because its model relies on housing starts. ORA also claims that SCE used models similar to ORA's in its 2012 GRC.[904]

We are not persuaded by ORA's criticisms and find that SCE has adequately justified that the PDL approach is valid. SCE's demonstration that its model outperforms ORA's in an extended validation period and better maintains the historical correlation between housing starts and new meter sets is compelling.[905]

TURN accepts SCE's basic model, updates it to the latest data, and makes minor changes to the equations. TURN shows that SCE's housing start and residential meter set forecasts for 2013 and early 2014 were higher than actual levels, and notes that SCE's vendors' housing forecasts had been revised downward for 2014-2015. However, the level of new commercial meters was slightly higher than forecast.[906]

[902] ORA-3 at 6-7 and Appendix A.
[903] SCE-26 V1 at 34-36, 40; SCE-66 at 4-10.
[904] ORA OB at 357-358, ORA-58, ORA-59.
[905] SCE-66 at 8-10.
[906] TURN-05 at 43-48.

SCE argues that TURN's update changes are unnecessary because the housing market is likely to pick up during 2015-2017.[907]

We find that TURN's forecast is most reasonable given its use of the most recent available information on new meter sets and housing start forecasts by SCE's vendors. Therefore, we adopt TURN's forecasts of new meters as shown below.

No party disputes the number of Agricultural meters, and we adopt SCE's forecast for Agricultural meters.[908]

New Meter Connections					
	Residential		Non-Residential		Agricultural
	# Requested	# Adopted	# Requested	# Adopted	# Adopted
2012	17,692	17,692	4,865	4,865	309
2013	27,758	21,841	5,114	5,252	316
2014	38,643	29,648	6,542	5,649[909]	332
2015	51,238	46,419	8,607	7,078	335
2016	56,320	57,101	10,698	9,527	339
2017	55,939	59,632	11,897	11,609	343

Applying this reduced meter forecast to SCE's forecast of customers[910] yields the following forecast,[911] which we adopt:

[907] SCE-26 V1 at 40-41.
[908] SCE-10 V1R1 at 61.
[909] We note that TURN-5 at 48 lists this value as "5,659," but elsewhere in TURN-5 (e.g., pages 56-59), the number used is "5,649." We apply the later value.
[910] SCE-10 V1R1 at 61.
[911] This calculation reduces the growth rate in number of customers in each class by the percent reduction in number of meters (i.e., approved customer growth rate = requested customer growth rate * (1-% reduction in meters)).

Year-End Customers by Customer Class						
	2012	2013	2014	2015	2016	2017
Residential	4,321,171	4,338,651	4,360,149	4,393,225	4,434,821	4,479,170
Agricultural	21,917	21,851	21,790	21,737	21,690	21,648
Commercial	549,855	553,610	558,233	564,415	572,869	582,779
Industrial	10,922	10,645	10,449	10,257	9,995	9,684
Public Authorities	46,600	46,395	46,287	46,229	46,220	46,238
Total Customers	4,950,465	4,971,151	4,996,907	5,035,863	5,085,595	5,139,519

Assuming that energy sales per customer are the same as in SCE's retail sales forecast,[912] we calculate the following forecast of energy sales, based on the above forecast of customers. We adopt this forecast:

Annual Retail Sales by Customer Class (GWh)						
	2012	2013	2014	2015	2016	2017
Residential	30,563	29,303	29,118	29,493	29,896	30,266
Agricultural	1,609	1,422	1,415	1,428	1,449	1,469
Commercial	40,541	40,806	41,109	41,718	42,268	42,583
Industrial	8,504	8,433	8,300	8,135	7,788	7,592
Public Authorities	5,263	4,875	4,667	4,675	4,663	4,568
Total Retail Sales	86,480	84,840	84,608	85,449	86,064	86,479

17. Other Operating Revenue

OOR is the revenue that SCE collects from customers other than general ratepayers; OOR reduces the general revenue requirement. In D.99-09-070, we adopted a Gross Revenue Sharing Mechanism (GRSM) for NTP&S that divides NTP&S revenues between shareholders and ratepayers. NTP&S is one component of OOR. In the 2012 GRC, we expressed concern about the recording and reporting of NTP&S "incremental costs" under the GRSM and noted that related concerns had been discussed in several prior GRCs. However, we

[912] SCE-10 V1R1 at 60.

concluded not to make any specific changes to the GRSM or SCE's estimated OOR in that decision, and instead stated that Energy Division's next affiliated transactions audit should include a detailed review of NTP&S.[913]

In this case, TURN raises the same concerns, estimating the consequence of these issues as "many million dollars of O&M expense, and tens of millions of dollars of inflated rate base." TURN notes that at the time of its opening brief, Energy Division's affiliated transactions audit was not yet available. Consequently, TURN recommends that we order SCE to obtain an independent audit, in consultation with Energy Division, and bear the cost of this audit as an incremental cost to NTP&S.[914]

SCE reviews several categories of OOR, the largest of which are $95.2 million of Other Electric Revenue in FERC Account 456 and $51.7 million of Rent from Electric Property in Account 454. SCE notes that its forecast for NTP&S is the $16.672 million threshold adopted in D.99-09-070.[915] SCE's total OOR estimate is approximately $201 million in 2015. ORA stipulates to this amount.[916]

We find SCE's undisputed forecast of total OOR reasonable and adopt it. As in the last GRC, we do not have adequate information before us to draw strong conclusions about the GRSM or SCE's recording and reporting of NTP&S incremental costs. However, we agree with TURN that it is appropriate to place a higher priority on an audit of NTP&S. Therefore, if Energy Division has not published an affiliated transactions audit that includes a focused review of NTP&S by the end of 2015, SCE shall contract for an independent audit. SCE shall consult with Energy Division in hiring the auditor, developing the scope of work, and managing the audit. At a minimum, the audit shall review NTP&S

[913] D.12-11-051 at 653-658.
[914] TURN-1 at 24-27 and TURN OB at 228-230.
[915] SCE-10V1R1 at 81-87.
[916] ORA-57R.

incremental costs from 2012 to 2015. SCE shall include the results of this audit, and/or the review from Energy Division's affiliated transactions audit, in its next GRC filing.

18. Cost Escalation

SCE developed escalation rates for several categories of labor, non-labor, and capital expenses during the recorded (2008-2012) and forecast (2013-2017) periods of this GRC. For many categories, SCE relies on data provided by IHS Global Insight – Power Planner. SCE also includes information from union contracts, Arizona Public Service, and the Handy-Whitman Index of Public Utility Costs for some categories.[917] ORA supports SCE's approach, and recommends using updated data.[918] SCE provided updated escalation information during the update phase of the proceeding.[919]

No party contests SCE's method. The method is the same or very similar to the method we approved in the previous GRC. SCE's method is reasonable and is adopted. Escalation rates during the post-test year period (2016 and 2017) are addressed in Section 19 below.

19. Post-Test Year Ratemaking (PTYR)

SCE requests a PTYR mechanism to provide additional revenues for SCE to conduct business in 2016 and 2017. The additional revenues provide for increases in capital expenditure to replace aging utility infrastructure and increases in operating expenses to account for price inflation. SCE argues that the proposed attrition revenue increases provide SCE a fair opportunity to recover its costs and earn a reasonable return for its investors. Thus, a PTYR

[917] SCE-10V1 at 71-83.
[918] ORA-4.
[919] SCE-73 and SCE-73C at 6-10.

mechanism helps SCE to maintain financial integrity as it faces increasing costs during the attrition years.

19.1. SCE's Proposed PTYR Mechanism

For its PTYR mechanism, SCE proposes to use a formula that will separately escalate O&M expenses and capital expenditures for 2016 and 2017. Additionally, SCE proposes to continue its current Z-factor mechanism that allows SCE to request recovery of exogenous and unforeseen costs incurred during the post-test years. To implement the post-test year revenue requirement, SCE proposes to file an advice letter by November 1st of 2015 and 2016. Details of SCE's proposal are described below.

19.1.1. Advice Letter Filing to Implement Revenue Requirement

SCE requests to instead implement the post year revenue requirements through annual advice letter filings. SCE proposes to file an advice letter by November 1 of 2015 and 2016, with the post-test year revenue requirement updated with the latest IHS Global Insight escalation rates.

19.1.2. O&M Costs

SCE proposes to escalate O&M expenses in the post-test years using the same price indexes that it proposes to escalate O&M expenses from the recorded year 2012 to test year 2015. In general, SCE will use the latest IHS Global Insight escalation rates, except for labor and medical benefits.

- Labor O&M - SCE proposes to escalate labor costs based on union wage increases and target wage increases for non-represented employees granted prior to the adoption of this decision.
- Benefit O&M – SCE requests to escalate medical costs by 8% in 2016 and 2017 and to apply this escalation rate to medical program costs and PBOP (Post Retirement Benefits Other Than

Pensions) costs. For other benefit categories, SCE originally requested the escalation rates listed in the table below:

Category	2016	2017
Medical Programs	8.00%	8.00%
Dental Programs	4.50%	4.50%
Vision Service Plan	2.00%	2.00%
Disability Programs	2.66%	2.65%
Group Life Insurance	0.00%	0.00%
Misc. Benefit Programs	3.03%	2.90%
Executive Benefits	2.66%	2.65%
401 (k)	2.66%	2.65%

SCE proposes that it will use the latest IHS Global Insight escalation rates to calculate the post-test year revenue requirements. SCE will update the post-test year revenue requirement in its annual advice letter filing by using the most up-to-date IHS Global Insight escalation rates that are available on October 1 of the year to calculate the next year's attrition increase. For 2017, the second attrition year, SCE proposes to use the latest Global Insight escalation rates to escalate 2015 authorized level of O&M expenses to 2016 and 2017 levels. But, the 2016 authorized level of O&M expenses will not be trued up resulting from updates to the escalation factor for 2016.

19.1.3. Capital-Related Cost Increases

SCE proposes to escalate capital costs in the post-test years according to a budget-based forecast of capital expenditures and capital additions. SCE also proposes to refund a portion of the associated revenue requirement to the extent that the budgeted capital expenditures are not spent, in a mechanism similar to a one-way balancing account. Under the budget-based forecast, SCE's board of directors determines the forecast budget for capital expenditures annually, subject to CPUC approval in this proceeding.

19.1.4. Z-Factor for Major Exogenous Cost Changes

SCE requests to continue its Z-factor mechanism. Currently, the Z-Factor mechanism allows SCE to seek recovery of extraordinary costs caused by exogenous events (Z-factors) that are outside of management's control and that are incurred during the post-test years. Z-factors are defined as events that cause a significant financial impact of more than $10 million. Either SCE or ORA can identify a Z-Factor event by submitting a Letter of Notification to the Executive Director. The Z-Factor mechanism provides SCE with the assurance that there is a clear process for it to request cost recovery for unanticipated events that have a significant financial impact on SCE.[920]

19.2. ORA's Position

ORA does not oppose granting SCE a PTYR mechanism to provide SCE a reasonable level of revenue increases for 2016 and 2017. ORA also does not oppose SCE's request to file advice letters to implement the attrition year revenue requirement. But, ORA opposes SCE's proposed PTYR mechanism and presents two different proposals as alternatives for consideration.

ORA's primary proposal recommends that the test year base revenue requirement be increased by 1.9% in 2016 and 2.3% in 2017. These percentages are calculated by adding 0.5% to the Urban Consumer Price Index (CPI-U). ORA argues that the Commission has used CPI as a basis for determining attrition year revenue increases in the past. Using CPI is simple and eliminates the need of using multiple indices for escalation. It also gives SCE an incentive to manage and control costs.

ORA also proposes an alternate recommendation which provides a separate escalation mechanism for O&M expenses and capital expenditures. For

[920] SCE-10V1R1 at 106-115.

general O&M expenses, ORA recommends escalating the adopted 2015 operational expenses by 2% per year. For medical benefit costs, ORA recommends an escalation factor of 6.6% in 2016 and 2017, based on forecasts by the Berkeley Healthcare Forum, compared to the 8% requested by SCE. For wage increases, ORA opposes SCE's request, noting that SCE's wage escalation rates for 2008-2013 are over 32% higher than IHS Economics figures. ORA also suggests that SCE should have an incentive to control labor cost increases via the PTYR mechanism. Hence, ORA recommends that wages be escalated by CPI, which are 1.5% for 2016 and 1.9% for 2017, or alternatively, by Global Insight's forecast for labor increases, which are 2.3% for 2016 and 2.6% for 2017.

For capital expenditures, ORA recommends escalating the adopted 2015 capital additions by 2.0% per year, since the increase in the forecast of capital additions from 2016 to 2017 is approximately 2.0%. ORA opposes using a budget-based forecast to determine capital-related revenue increases, arguing that the implementation of capital projects can change from plan. ORA notes that SCE underspent its forecasted capital expenditures by $296 million in 2013. In addition, ORA and all the other parties do not possess the resources to conduct detailed analyses of the utility's budget-based capital expenditures for the test year and the attrition years. Escalating adopted 2015 is more consistent with past Commission precedent.

ORA does not oppose the continuation of the Z-factor mechanism. ORA recognizes that the Z-factor mechanism has protected both SCE and the ratepayers by allowing revenue adjustments for unexpected and uncontrollable events.[921]

[921] ORA-25.

19.3. TURN's Position

TURN also recommends an alternate proposal, emphasizing that the PTYR mechanism should motivate the utility to control costs. For operational expenses, TURN recommends that, instead of using multiple indices for escalation, the PTYR mechanism should use a broad wholesale pricing index, specifically the All Manufacturing Commodity Index (WPI-IND). TURN argues that SCE should be incented to manage costs like other large companies that also have highly skilled workforces and employ specialized equipment. These should also include companies in unregulated manufacturing, utility, and mining industries. TURN argues that these companies face cost pressures similar to that of the utility, but also face market competition. Thus, an escalation factor based on a broad wholesale pricing index, like the WPI-IND, reflects inflationary cost increases in the marketplace. Since the WPI-IND is volatile, TURN recommends using a rolling three-year average. Additionally, TURN recommends that the second year attrition be trued up if the actual escalation is lower than the forecasted escalation in the first attrition year.

TURN recommends escalating capital expenditures by a method based on averaging seven years of recorded capital expenditures, excluding cost of removal, in constant dollars on a per customer basis. The average is then escalated for inflation and multiplied by the forecasted number of customers in the attrition year. Major plant additions, namely the Pole Loading program, are excluded from the average and are forecasted separately. TURN considers its capital proposal consistent with our "traditional" approach.

TURN's total proposed attrition year increase for each of 2016 and 2017 is approximately 3.9% per year.[922]

[922] TURN-18.

19.4. SCE's Rebuttal

SCE argues against using the CPI or the WPI-IND as a basis for PTYR mechanism. Even though escalating costs based on an index is simple, that approach does not accurately reflect the utility's cost of doing business. These indices do not use the same basket of labor, materials, and capital inputs that a utility uses. Rather, they only reflect inflationary price changes for goods and services that an average consumer or producer buys. Utility specific indices, like the IHS Global Insight indices, provide better estimates of utility cost increases. In addition, SCE argues that a price index cannot properly capture growth in capital expenditures.

In response to TURN and ORA's comments on labor costs, SCE emphasizes that it only seeks to include union and non-represented wage increases granted before this decision in its future PTYR increases.

SCE also notes that, with some modifications, ORA's alternate proposal for a two-part separate escalation mechanism for O&M expenses and capital expenditures could give SCE adequate attrition revenue requirement. These modifications include escalating O&M expenses with escalation factors that better align with SCE's costs and not the CPI. SCE also opposes using ORA's proposed 2015 level of capital as the basis for escalating capital additions, arguing that it is too low. But SCE does not take issue with ORA's proposal of escalating capital additions by 2%.[923]

19.5. Discussion

We allow SCE a PTYR mechanism to increase attrition year revenue requirement for 2016 and 2017. Attrition year revenue increases give SCE an opportunity to offset some inflationary price increases, increase capital

[923] SCE-26V1 at 48-74.

investments, and earn its authorized rate of return in the attrition years. Recognizing that SCE will face increased costs in the attrition years, revenue increases will help SCE to provide safe and reliable operations while maintaining financial integrity.

When deciding on an appropriate PTYR mechanism to use, we target a mechanism that is simple; accurately aligns with how costs are incurred for the utility; and gives the utility an incentive to manage costs while enhancing productivity. In weighing these different and sometimes competing goals, we adopt the following PTYR mechanism for SCE:

1) O&M expenses shall be escalated as proposed by SCE, using the same pricing methodology and pricing indices that we adopt for test year escalation, except for labor expenses [namely: disability programs, executive benefits, and 401(k)]. For labor expenses, we adopt ORA's recommendation to use Global Insight's most current forecast, consistent with ORA's recommendation, which is 2.3% in 2016 and 2.6% in 2017. For medical expenses, we adopt SCE's escalation rate of 8%, which we adopt for test year escalation (see Section 10.5.3 above). We also adopt SCE's proposed escalation rates for other benefits categories. For all other O&M expenses, we adopt SCE's proposal of using the latest IHS Global Insight escalation rates.

2) Capital-related revenues shall be escalated by increasing gross capital additions in the post test years at a rate of 2% per year above the 2015 authorized capital additions.

3) SCE's Z-factor recovery mechanism shall continue for 2016 and 2017.

4) We allow SCE to file an advice letter to implement the post-test year revenue requirement. SCE must file an advice letter by November 1st of 2015 and 2016. In these advice letters, SCE must update its post-test year revenue requirement, calculated by using the latest IHS Global Insight escalation rates for the following attrition year. For the second attrition year of 2017, SCE shall use the latest Global Insight escalation rates to escalate

> 2015 authorized level of O&M expenses to 2016 and 2017 levels, but the 2016 authorized level of O&M expenses will not be trued up to reflect the actual escalation factor for 2016.

We find that this PTYR mechanism strikes an appropriate balance between the goals described above as well as the parties' different positions. Even though applying a percentage increase based on CPI, as suggested by ORA's primary recommendation, is simple, it does not reflect how utilities incur costs. Since O&M expenses and capital expenditures affect the revenue requirement differently, we find a two-part attrition mechanism, where O&M expenses and capital-related revenues are separately escalated, is reasonable. These considerations form the bases for the two-part attrition mechanisms that were adopted in D.13-05-010 and D.14-08-032.

In adopting the O&M escalation rates, we agree with SCE that the Global Insight escalation rates more accurately forecasts the inflationary increases for the utility. We decline to adopt escalation based on the CPI, as proposed by ORA, or a broad wholesale pricing index, the WPI-IND, as proposed by TURN. We concur with SCE that both the CPI and the WPI-IND reflect price increases for goods and services that are not sufficiently similar to SCE's labor and capital inputs. Since the Global Insight escalation rates are specific to the utility industry, they more accurately reflect SCE's inflationary cost increases. SCE's estimates for other O&M expenses are reasonable.

For capital-related revenues, we allow SCE to escalate the adopted 2015 end-of-year gross capital additions by 2% for 2016 and an additional 2% for 2017. We concur with ORA's alternate recommendation that escalating capital additions by 2% is appropriate, since SCE's forecasted capital additions from 2016 to 2017 are increased by approximately 2%. We do not adopt SCE's

proposed budget-based forecast for capital expenditures. We find our comments in D.14-08-032 applicable:

> The [Attrition Rate Adjustment] is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee PG&E's rate of return through 2015 and 2016. The ARA is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.[924]

SCE shall implement its PTYR revenue requirement changes by advice letter, as proposed by SCE.

In addition, we allow SCE to continue its Z-factor recovery mechanism. The Z-factor mechanism, as recognized by D.12-11-051, applies for events that cause both a decrease and an increase in the utility's costs. These events can include tax rate changes or tax law changes.

The adopted escalation rates are summarized below:

Category		2016	2017	Notes
O&M - Labor				
	Disability Programs	2.89%	3.00%	Global Insight
	Executive Benefits	2.89%	3.00%	Global Insight
	401(k)	2.89%	3.00%	Global Insight
O&M - Other				
	Medical	8.00%	8.00%	SCE Estimate
	Dental	4.50%	4.50%	SCE Estimate
	Vision	2.00%	2.00%	SCE Estimate
	Group Life	0.00%	0.00%	SCE Estimate
	Misc. Benefit	2.29%	2.43%	Global Insight
Capital Additions		2.00%	2.00%	Applied to 2015 capital additions, based on 2015 authorized capital expenditures

In comments on the Proposed Decision, ORA and TURN suggest that the adopted PTYR mechanism inappropriately grants a larger increase in revenue requirement from 2015 to 2016 than SCE's final request. These comments are not

[924] D.14-08-032 at 652-653.

persuasive for two reasons. First, the difference between 2015 and 2016 is an arbitrary metric; instead we note that the total revenue requirement approved for 2016 is well below SCE's final request. Second, we note that the primary reason for the different rate of increase is that SCE's budget-based forecast of FERC-jurisdictional capital additions is considerably lower in 2016 than 2015. This decrease is not reflected in the 2% escalation rate applied to capital additions. Inherently, any simplification relative to a budget-based forecast (e.g. escalation of the test year amount by any factor) will exclude changes in the forecast after the test year. We accept this reality as part of the tradeoff between accuracy and simplicity.

20. Electric Plant

SCE presents a method for converting capital expenditures to Plant-In-Service. No party contests this method, and SCE asks for us to approve it.[925] SCE forecast its Plant-In-Service to grow from approximately $31 billion in 2012 to $46 billion in 2017. SCE's method describes booking costs to CWIP during construction and transferring the balance to rate base at the time of completion. Monthly capital additions (based primarily on the forecast of capital expenditures, in addition to other factors such as AFUD) and retirements are netted to determine the plant additions each period.[926] We find SCE's proposed method for converting capital expenditures to Plant-In-Service is reasonable and adopt it.

21. Depreciation

The purpose of depreciation expense is to allocate, in rates, the original cost of fixed capital assets, less net salvage value, over the life of the asset. Depreciation attempts to allocate the capital cost of the asset, including the Cost

[925] SCE OB at 300.
[926] SCE-10V2R1 at 1-18.

of Removal (COR), to all generations of customers on a pro rata basis during the life of the asset. Depreciation expense is a legitimate cost of service and allocates the costs of assets and their removal among all customer generations which benefit from those assets.

In this GRC, SCE applied the Straight-Line Remaining Life Depreciation method, historically applied by the Commission, where the undepreciated asset amount (original cost less accumulated depreciation and estimated net salvage) is depreciated in equal portions over the remaining life of the asset. The net salvage value includes the COR of the asset at the end of its useful life and any salvage value the asset may have at the time. Net salvage value is often negative (indicating that COR exceeds any positive salvage). The ratio of net salvage value to the original cost is called Net Salvage Ratio (NSR).

SCE combines most assets into broad groups for purposes of calculating depreciation which include a wide range of service lives and retirement characteristics. Some assets (e.g., individual generation assets), however, are addressed individually.

Generally, SCE argues that its currently authorized depreciation rates are too low, thus shifting costs from current customers to future customers. SCE claims that its depreciation proposals reduce, but do not eliminate this cost shifting, while the TURN and ORA proposals would exacerbate it.[927] As we noted in the last GRC decision,[928] SCE's calculations of past depreciation "deficits" and ongoing or future "deferrals" are merely calculations reflecting the difference between SCE's proposals for depreciation parameters and Commission-adopted or party-proposed parameters. SCE's point that if ongoing depreciation expense is "too low," future customers will be required to pay more

[927] SCE OB at 302.
[928] See, D.12-11-051 at 672.

may be valid. However, we recognize that determining the "right" level of depreciation expense is a complex exercise of forecasting future costs and events. SCE's calculations of deficits and deferrals are only valid if we assume that SCE's past and present proposals are correct. We do not start with this assumption; instead we remind SCE that it bears the burden of proof that its proposals are reasonable.

TURN and ORA argue that SCE has generally not met its burden of proof and specifically that SCE has not adequately complied with Commission requirements for added detail.[929]

In addition to changes in depreciation parameters, increases in plant balances also result in increases in SCE's depreciation expenses. SCE presents the combination of the two causes as shown below (in $ millions).[930]

Recorded 2012 Depreciation Expense	$ 1,298
Change in Accrual due to Proposals	$ 101
Change in Accrual due to Increase in Plant	$ 520
Test Year 2015 Depreciation Expense	$ 1,919

21.1. The Role of Judgment and Supplemental Studies

In D.12-11-051, we warned SCE against over-reliance on judgment without further explanation, and encouraged SCE to provide more transparency in its depreciation showing.[931] We also stated a variety of specific directives for SCE to address in its showing in this GRC; those directives are addressed below. TURN and ORA argue that SCE has not met its burden of proof for many of its proposals discussed below, in part because SCE has not adequately explained its use of judgment and in part because SCE has not provided adequate detail on its

[929] TURN OB at 245-246, citing D.12-11-051 at 664 and ORA OB at 384-385, citing D.12-11-051 at 685.
[930] SCE-10 V2R1 at 19.
[931] See, e.g., D.12-11-051 at 685.

analysis, particularly in its direct showing. Further, they claim SCE did not comply with the directives of D.12-11-051. As a result, TURN and ORA propose shareholder funded supplemental studies, focused on net salvage rates.[932] SCE claims that TURN and ORA have not demonstrated the value of such studies or why they should be funded by shareholders.[933]

Wherever ratemaking depreciation differs from the actual lives of utility assets and associated actual removal costs and actual salvage costs, there will be intergenerational shifting of depreciation costs. Therefore, one complicating factor in our review of depreciation parameters is that, under typical ratemaking approaches, future customers potentially bear the costs of any failure of the utility to meet its burden of proof for its proposals. These are the "deficits" and "deferrals" discussed above and in SCE's testimony. Stated differently, if we assume that SCE's proposed parameters are "correct" but are not adopted because SCE's showing in support of those parameters is inadequate, the cost of the deferral falls on future customers (who will need to pay more than their share for utility assets in order to make up past under-collections) rather than shareholders. For purposes of this discussion, we refer to this as under-collection risk. But the converse is true as well—if we were to adopt SCE's proposed parameters and they turn out to be incorrect, then current customers would face an undue cost burden resulting in a "windfall" for future customers.

As discussed in more detail below, we agree with ORA and TURN that there are a number of significant shortcomings in SCE's showing for the mass property accounts. To address these shortcomings in light of under-collection risk, we offer all parties guidance for the following GRC below.

[932] See: TURN-10 at 57 and ORA-23 at 1-2.
[933] SCE OB at 306-307.

First, we believe that SCE can and must do more to explain and justify its use of judgment in its depreciation showing. SCE provides a lengthy discussion of the role of judgment in depreciation analysis, concluding that "[t]here is no single correct result from statistical analysis; hence, there is no answer absent judgment."[934] We agree with SCE that, under certain circumstances, expert judgment can and should be used to complement, balance, and even override statistical results or other quantitative, factual information. We further agree with SCE that judgment is required to make a decision on issues with multiple, conflicting factors suggesting different conclusions. However, we also believe that an expert witness must be able to explain the quantitative or qualitative basis for such application of judgment, in any specific instance. A statement that "our judgment suggests X" without supporting analysis or explanation cannot meet the burden of proof on a contested issue, particularly if the recommended conclusion conflicts with statistical results and no countervailing evidence is identified. An adequate showing will avoid statements of judgment without supporting analysis or explanation.

Second, we direct SCE to provide considerably more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense. At a minimum, this detail shall include:

1. A quantitative discussion of the historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per-unit COR.
2. A quantitative discussion of the historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix.

[934] SCE-10V3 at 11-12.

3. A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross-reference the proposal for life characteristics.
4. An account-specific discussion of the process for allocating costs to COR.

Third, we recognize that this is at least the second consecutive GRC that the Commission has expressed serious concern with the quality of SCE's depreciation showing. In order to motivate SCE to take these concerns seriously in developing its direct showing for its next GRC, we encourage ORA and TURN (and any other interested party) to consider making proposals in that GRC to shift a portion of the under-collection risk from future customers to SCE's shareholders. Parties should only make such proposals if SCE's direct showing in the following GRC exhibits the same types of shortcomings, discussed here and in D.12-11-051, in a widespread manner.

21.2. Average Service Life (ASL) and Survivor Curves

Of the mass property categories, SCE proposes no change in the ASL for several FERC accounts, an increase in ASL for seven accounts, and a decrease in ASL for a single account (355 – Transmission Poles and Fixtures).[935]

SCE generally relies on a combination of Simulated Plant Record (SPR) results, input from SCE personnel, and expert judgment on the part of SCE's depreciation consultant to support its positions.[936] ORA and TURN place more emphasis on SPR results.[937] Each of the three parties refers to other utilities when the comparison purportedly supports their position. ORA and TURN also argue, as noted above, that SCE has not met its burden of proof. TURN devotes six

[935] SCE-10 V3, Study at 1-2.
[936] See SCE-26V3 at 27-80.
[937] ORA OB at 390-396; TURN-10 at 29-45.

pages in its opening brief to a detailed review of SCE's showing for FERC Account 355 (Transmission Poles and Fixtures) concluding that there is "virtually NOTHING" to substantiate SCE's claim that it improved its showing relative to the 2012 GRC for this account.[938] As discussed below, we agree with TURN that SCE has not met its burden of proof on the subject of ASL and survivor curves for Account 355, particularly in light of the direction in D.12-11-051 to provide a better description of changes to underlying causes of retirement, life characteristics, or mix of investments considered when forecasting ASL in an account.[939] However, we do not reach any general conclusion that SCE's proposals are less reasonable than those of TURN and ORA. While we agree with TURN that SCE's showing on ASL and survivor curves is generally disappointing and overly reliant on unexplained "judgment," not all of the accounts have the same types of misleading statements as those in Account 355.

SCE frequently characterizes TURN and ORA proposals as overly reliant on SPR statistics, without appropriately considering other factors. As a general matter, this critique may be valid in some cases, however we only find this critique persuasive in the accounts for which SCE specifically identifies the other factors and explains its analysis of those factors.

Various parties frequently cite the life curve combinations used either by specific utilities or by a large sample of utilities. At the same time, the parties appear to agree that SCE-specific data is most informative, and frequently criticize comparisons to specific other utilities as arising from different circumstances. We agree that comparisons may be informative if one or more directly comparable utilities are identified. However, broad comparisons (e.g.,

[938] TURN OB at 249-255; quote from pg 255, emphasis in original.
[939] D.12-11-051 at 685.

three of 95 do x while six of 95 do y) provide little value unless there is a clear industry consensus (which we do not see in any of the contested accounts discussed below).

21.2.1. Account 355 – Transmission Poles and Fixtures

SCE proposes retaining the existing R1 survivor curve and reducing the ASL from 50 to 45 years; TURN proposes increasing ASL to 51 and changing to an R0.5 curve. Both parties discuss SPR results, comparisons to other utilities' survivor curves, and the impact of SCE's pole loading and through-boring programs on ASL.

In direct testimony, SCE claims that its proposed R1 curve is "ranked well" and suggests that this is consistent with "predominant" choices in the industry. SCE simply dismisses the highest ranked R0.5 curve as being flatter than expected and only used by one of 81 companies. Finally, SCE generally asserts that the PLP will shorten the lives of existing poles and that the through-boring program may increase ASL in the future, but is currently a small factor. SCE's closing statement of its direct showing could be read as a summary of SCE's case, had it been presented alongside actual analysis. Instead it is merely a conclusory assertion: "[b]ased on the SPR analysis, input from Company personnel, and judgment regarding the asset groups in this account, this study recommends moving to a 45-year life with a R1 dispersion curve for this account."[940]

In its testimony, TURN documents that the ASL for this account has seen a "general upward trend" since the 1980s, and suggests that SCE "seeks to roll back" the five-year increase adopted in the last GRC. TURN discusses through-boring, noting that SCE began this process in 2004 and that SCE engineers claim this could increase life expectancies of wood poles to 60-70 years.

[940] SCE-10 V3, Study at 34.

TURN suggests that the PLP will lengthen the overall life of the account due to repair of degraded poles. TURN notes that the five best fitting curves all show increases in ASL since the last GRC.[941]

In rebuttal, SCE contends that TURN's claims on life expectancy do not take all information into account, but does not clearly identify what was left out or how this would impact the analysis. SCE cites its workpapers (Ex. TURN-93) which do contain some information supporting the claim that the life of older wood poles may be shorter than the ASL proposed by TURN, but this information does not quantify this impact relative to the other types of poles or on the account as a whole.[942] Further, SCE repeats its argument about the limited current impact of through-boring, adding only that "most of the existing assets in service did not receive this pole treatment."[943] SCE suggests that there are "numerous" factors leading to retirements before design life for poles. Further, SCE disagrees with TURN on the impact of PLP, stating that SCE will no longer repair poles after a failed inspection, and they will instead be replaced. SCE provides a comparison of SPR results (ASL and Conformance Index {CI}) for each of the proposed survivor curves, noting that for bands 40 years and longer neither curve produces an excellent CI and claiming that the 50+ year bands "make the R1 curve a superior choice." SCE's provided table plainly supports exactly the opposite conclusion: each of the 50+ year bands shows a higher/better CI for TURN's proposed R0.5 curve than for SCE's proposed R1. Finally, SCE's witness notes that he would expect a more "peaked" dispersion than the R0.5 and that TURN's proposal is unreasonable because it would have

[941] TURN-10 at 34-35.
[942] SCE later notes that steel concrete and light duty steel poles account for 46.0% of the assets in the account, nearly as much as wood composite poles (47.6%). SCE-26V3 at 43.
[943] SCE-26V3 at 41.

some assets living to age 100. SCE claims that no other company uses R0.5, a direct contradiction to data shown in SCE's direct testimony.[944]

In hearings, SCE's witness further undermined a number of the points made in SCE's rebuttal. First, he conceded that the 40 year band SPR result for TURN's proposed R0.5 curve is "not any different" than an excellent CI.[945] Further, he admitted recommending curves that include lives of the longest lived assets greater than 100 years for some utilities, but did not explain why he contended this was unreasonable for SCE.[946] SCE's testimony on the impact of through-boring was inconsistent and contradicted written testimony, leaving the Commission with no clear evidence to understand through-boring's impact in this account.[947]

In conclusion, we agree with TURN that SCE's showing for Account 355 is conclusory at best, and misleading or inaccurate at worst. However, we do not entirely accept TURN's proposal. In our view, the SPR ASL results for the R0.5 curve better support a 50 year ASL (e.g., we round down the 50.4 and 50.6 year results in the 50, 60, and overall bands). We adopt a 50 R 0.5 for Account 355.

21.2.2. Account 353 – Station Equipment

Both SCE and TURN propose increases from the current 40 year ASL, with SCE proposing a 41 R 1, and TURN proposing a 45 R 0.5. TURN's proposal has better CI results, but as SCE points out, the difference is small.[948] However, TURN points out the top three curves all show an average ASL between 45 and 48 years.[949] Although the SPR statistics only weakly favor TURN's proposal over

[944] SCE-26V3 at 40-44.
[945] 15 RT 1571.
[946] 15 RT 1651.
[947] 15 RT 1575-1578. See also: TURN OB at 253-254.
[948] TURN 10 at 30, SCE-26V3 at 31-32.
[949] TURN-10 at 30.

that of SCE, SCE has not provided any persuasive rationale to overcome the SPR statistics. Accordingly, we adopt TURN's proposal.

21.2.3. Account 354 – Transmission Towers and Fixtures

SCE proposes no change to the 65 R 5, while TURN proposes an increase in ASL to 67 R 5. TURN suggests that best fitting curves in the last several GRCs have shown increasing ASLs and that in this GRC the 20-year band shows a 68-year ASL.[950] However, the longer experience bands are consistent with SCE's proposed 65-year ASL.[951] Accordingly, we will retain the current 65 R 5.

21.2.4. Account 356 – Transmission Overhead Conductors and Devices

SCE proposes increasing the ASL to 56 while retaining the R4 curve; TURN recommends a 62 R3. TURN states that the R3 curve ranks higher than the R4 for all bands, and is the most frequently used in the industry, according to SCE's depreciation study. TURN also observes that shorter bands suggest the longer ASL and that other utilities use ASLs up to 70 years. TURN claims the statistics justify ASLs up to 69 years. Finally, TURN suggests that aluminum conductor can last far longer than the ASLs considered here.[952] SCE suggests that TURN misconstrues academic texts and the recommendations of SCE's witness in other jurisdictions. SCE's SPR statistics show that TURN's proposed curve very slightly outperforms SCE's in all bands, but neither curve reaches an "Excellent" CI for any band wider than 10 years.[953] SCE's various critiques of TURN's arguments appear valid. However, SCE cites no rationale for discounting the better SPR statistics of the R3 curve, therefore we adopt the R3. However, we

[950] TURN-10 at 32-33.
[951] SCE-26V3 at 36.
[952] TURN-10 at 37-38.
[953] SCE-26V3 at 47-49.

place more weight than TURN on the SPR recommended by the wider bands, and select a 61-year ASL.

21.2.5. Account 362 – Distribution Station Equipment

SCE proposes retaining the current 45 R1.5. ORA proposes a 50 R0.5, arguing that it has consistently better CI with equal Retirement Experience Index (REI) to SCE's proposal.[954] TURN recommends a 51 R0.5, noting better SPR statistics and claiming that the 51-year ASL is consistent with the recommendations of SCE's witness on behalf of other utilities.[955] SCE notes that the CI values are fair or poor for both curves in bands 30 and longer and suggests that the R0.5 is "too flat of a dispersion pattern based on the results of the SPR analysis, the predominant curve patterns in the industry, the types of assets in the account and the current approved parameters."[956] Of these reasons, SCE does not include any analysis or explanation of its claim that the SPR results show that R0.5 is too flat, states that more (18 of 95) companies use R1.5 than R0.5 (5 of 95), and suggests that factors the Commission found important in the last GRC have not changed. For the types of assets in the account, SCE references its workpapers (Exhibit TURN-93) which include some discussion (apparently from workpapers dating to the 2006 GRC) discussing the design life of items in the account, and concluding that the degree to which SCE's assets outlive the design life may be expected to decrease.[957] Based on this design life information, we conclude that the ASL predicted by SCE's R1.5 curve is more reasonable, and adopt SCE's 45 R1.5.

[954] ORA-23 at 14-15.
[955] TURN-10 at 39-41.
[956] SCE-26V3 at 55.
[957] TURN-93 at 143-144.

21.2.6. Account 364 – Distribution Poles, Towers, and Fixtures

SCE recommends changing from a 45 R1 to a 45 R0.5, noting the R0.5 outranks the R1 in the 50+ year bands.[958] ORA recommends a 47 R0.5, citing engineering data in SCE's workpapers and ASL statistics from SPR.[959] TURN recommends a 47 L0.5, claiming that SCE's SPR analysis "lacks cohesion," notes that the 20-40 year bands yield longer ASLs, and finds that the L0 and L0.5 curves are the best fits for bands 40-60 (and almost for the 30 year band). TURN also discusses SCE's engineering data, noting the design life of new wood poles and all composite and steel poles is 60-70 years, that SCE's territory has favorable climate for long life of wood poles, that a significant share of investment (in $) is in newer poles, and that the average age poles retired in each of 2001-2012 were older than 45 years.[960] SCE rejects ORA's claims, stating that ORA disregards the same workpaper information cited by TURN (i.e., TURN-93 at 163-165). SCE does not rebut TURN's discussion of the engineering data. SCE also suggests that both ORA and TURN inappropriately rely on shorter experience bands to support their recommendations, notes that both curves have poor CI for bands 30+, and that almost all of the 40+ year bands suggest an ASL 45 years or less.[961] We find that the 47 years life proposed by TURN and ORA is well supported by the engineering analysis in SCE's workpapers, as explained by TURN. Further, while the difference is slight, the SPR statistics favor TURN's proposed L0.5 curve. Accordingly, we adopt TURN's proposed 47 L0.5.

[958] SCE-10V3 at 48-49.
[959] ORA-23 at 16-17.
[960] TURN-10 at 43-45, TURN-93 at 161-163.
[961] SCE-26V3 at 57-61.

21.2.7. Account 367 – Underground Conductor & Devices

SCE proposes retaining the R1 curve, but increasing to a 42-year ASL. SCE notes that the R0.5, L0, and R1 curves are best ranked for all bands, and have high REIs. R1 shows a 42-year life for all bands greater than ten years.[962] ORA proposes a 49 R0.5, noting that R0.5 has better CI in every band and shows ASLs between 49.6 and 50.8 with only a slightly lower (REI) (96%). ORA notes that neither curve is used by many companies. Finally, ORA notes that engineering information provided by SCE supports longer service lives for distribution cable installed since 2000.[963] In response, SCE suggests that R1 is more common across the industry, that ORA's proposed 23% increase in the ASL is too aggressive, and that only four curves have an ASL greater than 42 years. Further, SCE notes that the assets in this account are fairly homogeneous, suggesting a higher mode frequency.[964] The difference in number of companies using the curves (one vs three) is too slight to be persuasive. We agree with ORA's view of the engineering information supporting a longer ASL and the SPR suggesting a R0.5 curve. However, we also find SCE's point about the homogeneity of the assets compelling and are hesitant to make such a drastic change as ORA suggests. Accordingly, we adopt a 45 R0.5 as a modification of ORA's proposal; we anticipate that if the SPR statistics continue to favor an R0.5 curve with longer ASLs in future GRCs, we will further increase the adopted ASL.

21.2.8. Account 368 - Line Transformers

SCE proposes to increase the ASL from 30 to 33 and move to a flatter R1 from the current R5. The top ranked curves are R0.5, L0, and R1, each with REIs close to 100, but low CI. SCE focuses on 36 R0.5 vs 33 R1, and concludes that

[962] SCE-10V3 at 54-55.
[963] ORA-23 at 17-19.
[964] SCE-26V3 at 62-67.

33R1 is preferred because the longer life and flatter 36 R0.5 are not appropriate for this account.[965] ORA argues that the 36 R0.5 curve is the best fit in every observation band and notes that each band is used by eight other companies.[966] In rebuttal, SCE notes that the CI differences are small and that the life of overhead transformers ranges from 25-35 and underground transformers 15-25, and that these two asset types comprise 67.5% of the account.[967] We agree that the engineering life estimates are more compelling than the slight difference in SPR statistics and approve SCE's proposal.

21.2.9. Account 369 – Services

SCE proposes retaining the current R2 and increasing the ASL from 40 to 42. SCE notes that the top ranked curves are "very flat" and that REIs are close to 100, but CI are poor and fair. SCE suggests that the flat curves indicate changing characteristics. SCE claims R2 is the predominant curve in the industry.[968] ORA agrees that the SPR data indicates a longer ASL and notes that the top ranked curve is a 57 R0.5, with excellent REI, but considers this 17-year increase too extreme. ORA recommends a 50 R1 noting that it is one of four curves consistently outranking SCE's proposed R2.[969] SCE contends that the CI values are too low and too close between the two curves to strongly favor the R1 and that homogeneity would suggest a curve with higher mode frequency dispersion.[970] We note that the R2 curve is only slightly more commonly used than the R1 (18 vs 14) and that the R1.5 is not far behind (11).[971] We agree that ASL is increasing, and that the SPR data suggests that life characteristics may be

[965] SCE-10V3 at 56-57.
[966] ORA-23 at 19-20.
[967] SCE-26V3 at 68-70; TURN-93 at 180-191.
[968] SCE-10V3 at 58-59.
[969] ORA-23 at 20-21.
[970] SCE-26V3 at 71-76.
[971] SCE-10V3 at 58.

changing. From our review of the SPR data,[972] we note that the R1.5 curve suggest a 44.5-year life and consistently has better CI values than the R2 curve proposed by SCE. Further, a 45 R1.5 does not represent as extreme a change as ORA's proposal. We adopt a 45 R1.5.

21.2.10. Account 373 – Street Lighting

SCE proposes to retain the current 40 L0.5, noting that the top ranked curves are low modal which SCE finds reasonable given the variety of assets in the account. SCE notes these curves are common in the industry and that CI values are fair or poor for all bands greater than ten years.[973] ORA proposes an increase in ASL to a 42 L0.5 based on SPR data.[974] SCE argues that the CI is too low to support an increase in ASL, that most other curves show shorter ASLs, and that ORA's recommendation does not account for SCE's operational information suggesting a 38.5-year life.[975] We agree with SCE that the operational information is more compelling than the SPR statistics in this instance, and approve the 40 L 0.5.

21.2.11. Other Accounts and Summary

There are a number of other accounts for which no party contested SCE's showing. Unless otherwise noted above, SCE's proposals are approved. The following table shows a summary of the contested accounts.

[972] TURN-92 at 219-225.
[973] SCE-10V3 at 61.
[974] ORA-23 at 21.
[975] SCE-26 V3 at 76-78, TURN 93 at 205.

Account		2012 GRC	SCE	TURN	ORA	Adopted
TRANSMISSION PLANT						
353	Station equipment	40 R 1	41 R 1	45 R 0.5		45 R 0.5
354	Towers & Fixtures	65 R 5	65 R 5	67 R 5		65 R 5
355	Poles & Fixtures	50 R 1	45 R 1	51 R 0.5		50 R 0.5
356	Overhead Conductors & Devices	50 R 4	56 R 4	62 R 3		61 R 3
DISTRIBUTION PLANT						
362	Station Equipment	45 R 1.5	45 R 1.5	51 R 0.5	50 R 0.5	45 R 1.5
364	Poles, Towers & Fixtures	45 R 1	45 R 0.5	47 L 0.5	47 R 0.5	47 L 0.5
367	Underground Conductors & Devices	40 R 1	42 R 1		49 R 0.5	45 R 0.5
368	Line Transformers	30 R 1.5	33 R 1		36 R 0.5	33 R 1
369	Services	40 R 2	42 R 2		50 R 1	45 R 1.5
373	Street Lighting & Signal Systems	40 L 0.5	40 L 0.5		42 L 0.5	40 L 0.5

21.3. Cost of Removal (COR) and NSR

SCE proposes a weighted-average increase of 17.88% in its NSR for T&D accounts, representing an increase in future COR of almost $4.2 billion.[976] As with the life analysis discussed above, TURN and ORA contend that SCE did not meet its burden of proof and did not comply with Commission directives in D.12-11-051; SCE contends that it did.

In many of the accounts, the proposed NSR is negative. For simplicity, we will refer to changes in negative NSRs as an increase if it is a move toward a more negative number (e.g., an increase from -10% to -20%) and vice versa.

One particularly contested requirement is the Commission's statement that "SCE shall provide testimony in its next GRC to provide more information about

[976] SCE-26V2 at C-1.

the COR in asset accounts where SCE's proposed NSR is at least 25% more than comparable industry averages."[977] We refer to this requirement as the "25% directive." SCE argues that it was not aware of such statistics, but necessarily complied with the 25% directive by providing more information for all accounts.[978] TURN argues that SCE did not comply with this requirement, in part by misinterpreting the requirement to refer to recorded data rather than requested or approved NSRs, and in part by devoting no significant discussion to the issue in its direct testimony.[979]

Another contested requirement is that SCE review its allocation practices to ensure that no costs of installing new equipment are booked as COR.[980] SCE argues it complied with this requirement because its outside witness "provided an unbiased and independent perspective" and concluded that no changes were required.[981] TURN argues that SCE's showing on this point is insufficient, and amounts to little more than the utility's hired witness stating the utility's process is adequate, in part based on review of a 2004 report.[982] We agree with TURN – SCE has done little to assure the Commission that it is not inappropriately booking installation costs to COR. This problem is fundamental – SCE's primary justification for its positions on NSR is historical COR data. Other parties also rely on this same historical data. SCE's showing does include any significant quantitative showing beyond its review of historical, account-level NSR data. For example, SCE's only quantitative discussion of future trends in COR or retirement mix are in rebuttal to TURN. While we do not make any

[977] D.12-11-051 at 686.
[978] SCE OB at 304.
[979] TURN OB at 256-258.
[980] D.12-11-051 at 683.
[981] SCE OB at 305.
[982] TURN OB at 260-261.

across-the-board reductions to SCE's proposals based on this problem, we factor this shortcoming in SCE's showing into our analysis of the individual accounts.

In PG&E's most recent GRC, we adopted a cap on the rate of increase in negative NSRs for disputed accounts of 25% of PG&E's requested increase (e.g., if the previously approved NSR was -50% and PG&E requested -100%, we adopted an NSR no more negative than -62.5%). The primary rationale for this cap was gradualism. Specifically, we found that this cap appropriately balanced the rate increase to current customers with the costs to future customers of any deferred COR.[983]

21.3.1. Account 352 – Transmission Structures and Improvements

SCE proposes increasing the NSR from -30% to -35% noting that recent experience has ranged from -50.05 to -77.35%.[984] ORA recommends no change to this account, citing the 25% NSR directive in D.12-11-051 and stating that SCE provided less testimony than previously. In calculating the industry average, ORA excludes PG&E as an outlier.[985] SCE criticizes ORA's approach in general, particularly with regard to excluding PG&E. SCE notes that its COR data shows NSRs for 2010-2012 that are higher than those considered in the 2012 GRC.[986] We note that SCE's recorded data for those years is far higher than SCE's proposal. Accordingly we approve SCE's requested increase to -35%.

21.3.2. Account 353 – Transmission Station Equipment

SCE proposes an increase from -5% to -15% based on 10-year rolling average of -18%.[987] ORA recommends an increase to -10%. ORA suggests that

[983] D.14-08-032 at 596-602.
[984] SCE-10V3, Study at 88.
[985] ORA-23 at 24-26.
[986] SCE-26V3 at 86-88; SCE-10V3, Appendix E at 1.
[987] SCE-10V3, Study at 88-89.

increasing copper prices should lead to an increase in gross salvage, thus making the NSR less negative, but notes that historical salvage data does not show this relation.[988] TURN proposes no change, claiming that SCE's change to exclude spare parts is inappropriate. TURN further argues that future NSR values are likely to be more influenced by transformers, therefore potentially realizing higher gross salvage and less negative NSR. TURN also argues that emergency labor is not appropriately considered by SCE.[989] SCE notes that net salvage over the last four recorded years has been more negative than -20% despite high copper prices and high gross salvage, noting that there is no certainty of future copper prices remaining high. SCE argues that TURN's spare parts argument is irrelevant on the basis that this is small ($52 million) relative to the account ($3.9 billion), but comments that they "dramatically influence" the results. Further, SCE notes that spare parts are internal transactions, are not sold, and were removed from retirement, gross salvage, and life analysis for the depreciation study. SCE suggests that TURN misconstrues the relative NSR impact of transformers and switches, arguing that both are long-lived assets and that transformers are more costly to remove.[990] We agree with SCE that the recorded data supports an increase in the NSR and are not persuaded that copper prices or other factors will change NSR in the future. Accordingly, we adopt SCE's proposed increase to -15%.

21.3.3. Account 354 – Transmission Towers and Fixtures

SCE proposes an increase in the NSR from -70% to -100%, citing five and ten-year averages of -200% and -185%.[991] ORA recommends retaining the current NSR, noting that it is consistent with industry data, after excluding an outlier that

[988] ORA-23 at 27-30.
[989] TURN-10 at 59 – 62.
[990] SCE-26V3 at 88-94.
[991] SCE-10V3, Study at 89.

is 22 times greater than the second highest reported NSR.[992] TURN recommends a -40% NSR, discounting SCE's recorded data as being not representative for two reasons. First, very little has been retired. Second, double circuit towers have been disproportionately represented in recent retirements. TURN anticipates future economies of scale will bring unit COR down in the future. TURN claims the five-year mean, median, and mode of SCE's witness's proposals for this account is -20%.[993]

SCE rejects ORA's outlier removal and claims its proposal is consistent with the industry data. SCE rebuts TURN's small sample size arguments by claiming that there is no reason to suspect the sample is not representative. Further, SCE admits that there may be some economies of scale to removing transmission towers, but argues that they will be very small in comparison to the total cost.[994]

Given the small sample on which SCE's historical data is based, we do not find a compelling reason to increase the NSR for this account. Further, SCE has not advanced any argument why its NSR should be significantly higher than the industry data cited by TURN and ORA, and agree with ORA that excluding the extreme outlier for this account appears appropriate. Accordingly, we adopt a slight decrease in NSR to -60% in order to make a conservative move toward the industry central tendency unless SCE's actual experience or other evidence in future GRC's supports a higher NSR.

21.3.4. Account 355 – Transmission Poles and Fixtures

SCE proposes to increase the NSR from -70% to -85%, claiming the recent five and ten-year averages are -107% and -115%.[995] ORA recommends -72%

[992] ORA-23 at 30-32.
[993] TURN-10 at 63-65.
[994] SCE-26V3 at 94-99.
[995] SCE-10V3, Study at 90.

claiming that this is consistent with PG&E and the industry median and mean after removing certain outliers. Further, ORA anticipates that the pole loading program will decrease costs in this account by economies of scale and reducing the fraction of emergency work.[996] SCE objects to ORA's removal of outliers and use of the median statistic, but does not respond to ORA's argument about future cost reductions.[997] We find ORA's argument that per unit COR will be lower in the future due to the increase in non-emergency retirements persuasive, and we adopt ORA's proposed -72%.

21.3.5. Account 356 – Transmission Overhead Conductor and Devices

SCE proposes an increase from -80% to -100%, citing five and ten-year averages of -204% and -171%.[998] ORA recommends no change to this account citing the 25% directive and industry mean and median figures ranging from -35% to -71%.[999] TURN recommends a decrease to -50%, claiming that this is above the central tendency of the recent recommendations of SCE's witness for other utilities (-30 to -38%), and that this proposal results in annual accruals approximately equal to the ten-year average of SCE's actual total COR. TURN claims SCE's historical data are inappropriate to rely on.[1000] In rebuttal, SCE repeats its arguments based on recorded data, notes that six other utilities report higher values, and argues that it met its burden of proof. Without explanation, SCE expresses surprise that it is not the highest in the industry for this account.[1001] We agree with ORA that SCE has not explained its deviation from industry averages and adopt ORA's proposed -80%.

[996] ORA-23 at 32-34.
[997] SCE-26V3 at 99-101.
[998] SCE-10V3, Study at 90-91.
[999] ORA-23 at 35.
[1000] TURN-10 at 66-67.
[1001] SCE-26V3 at 102-104.

21.3.6. Account 362 – Station Equipment

SCE recommends an increase in NSR from -20% to -30%, citing five and ten-year averages of -58% and -43%.[1002] ORA and TURN each recommend no change. ORA notes that industry mean values are approximately -22% (or -15% excluding SDG&E) while the industry median is -15%.[1003] TURN claims that transformers have been underrepresented in recent retirements by 68% relative to their share of plant balance and that copper prices are currently high, arguing that these factors will increase gross salvage. Further TURN claims that SCE's witness has consistently testified to lower NSR for other utilities.[1004] SCE rejects ORA's analysis, claiming that SDG&E's experience indicates that COR in California is high. SCE also claims that transformers are not the only long-lived assets in the substation, are more expensive to remove than other assets, that copper prices have only a small impact on NSR for this account, and that eight other companies report higher NSR than requested by SCE.[1005] While we agree with SCE that copper prices are not a large factor, we find that TURN's argument about changing retirement mix has some merit. SCE's rebuttal that transformers are expensive to remove is almost entirely based on factors that would also make them expensive to install (e.g., weight and bulk). This argument is not convincing in terms of NSR because both parts of the ratio are impacted. We adopt -25% in order to balance this concern against SCE's recorded data.

21.3.7. Account 364 – Distribution Poles, Towers, & Fixtures

SCE proposes an increase in the NSR from -190% to -225%, noting the recent five and ten-year averages both exceed -410% and that it does not foresee a

[1002] SCE-10V3, Study at 92-93.
[1003] ORA-23 at 35-36.
[1004] TURN-10 at 68-69.
[1005] SCE-26V3 at 105-109.

change in the fraction of emergency work.[1006] ORA proposes no change, claiming that COR on a per pole basis has been stable or possibly decreasing. Excluding either one or two outliers, ORA calculates industry means in the range of -113% to -152%, and argues that SCE has neither complied with the 25% directive nor met its burden of proof. ORA suggests that SCE's proposed increase in annual net salvage collections (greater than $579 million) is not justified by the 218 words of SCE's testimony.[1007]

TURN recommends a decrease in NSR to -132% on the basis that SCE's recorded COR values are industry outliers and suggesting that SCE's allocation between COR and cost of installation is part of the problem. TURN notes that SCE's proposal is much higher than for any other utility that SCE's witness has performed the depreciation study. In particular, TURN discusses a utility in Texas (Southwestern Public Service Company, or SPS), asserting that SCE's COR on a per pole basis is 7.6 times higher ($2,400 vs $300). TURN postulates that labor is a major portion of COR, and that labor is approximately 23% more expensive for SCE than SPS, and concludes that labor or other cost differentials are unlikely to explain the difference in COR. TURN contends that SCE's allocation process has not been updated enough (e.g., it assumes no relative changes in labor and materials costs since 2004) and generally challenges the allocation factors. TURN proposes -132% because that is the "most negative and most recent level" proposed by SCE's witness on behalf of another utility.[1008]

SCE rejects ORA's and TURN's characterizations that its COR is unusually high. SCE's basis is industry data without removing ORA's outliers and claiming that there are seven utilities with higher COR for this account. Further, SCE

[1006] SCE-10V3, Study at 93-94.
[1007] ORA-23 at 37-39.
[1008] TURN-10 at 70-75.

contends that the per pole COR is trending up, not down, relying on the same data as cited by ORA. SCE's witness rejects TURN's comparison to SPS based on "a dramatic difference in the effort required to replace a pole in many cases" and discusses a supporting anecdote. Further, SCE suggests that TURN's calculated $300/pole for SPS is inaccurate, and provides a comparable value of $447 for SPS. SCE also observes that TURN's allocation theory would suggest that SPS books more cost to new poles than SCE, but SCE's costs are in fact higher. SCE alleges that it pays $100 per pole for disposal and that SPS faces no similar disposal fee. Finally, SCE defends its allocation process noting that allocations are specific to the configuration of the poles and alleging that work effort per task is unlikely to change over time.[1009]

SCE's response to ORA and TURN's allegations is insufficient to justify the full requested increase. SCE's historical data suggests an increase is warranted, but SCE's showing that the allocation practices are reasonable is incomplete. However, TURN's suggestion to totally discount SCE's recorded data is extreme, and we decline to adopt this approach. While there are clearly differences between SCE and SPS and their territories, SCE's anecdotal evidence and reference to disposal fees does not prove that SCE's $2,400 per pole COR is reasonable. Consistent with the logic of gradualism that we applied to PG&E, we will adopt a -210% NSR. This balances the increase demonstrated by SCE's recorded data, our ongoing concerns with SCE's showing on its allocation practices, and the rate of increase in depreciation rates.

21.3.8. Account 365 – Distribution Overhead Conductors and Devices

SCE proposes an increase from -110% to -125% citing five and ten-year averages of -277% and -200%. ORA recommends no change, citing industry

[1009] SCE-26V3 at 108-115.

means and medians ranging from -50% to -84%, noting that the mean drops to -63% if PG&E is excluded.[1010] TURN recommends a decrease to -85% alleging problems in SCE's data and citing industry comparisons. TURN claims that the highest recommendation that SCE's witness has made for any utility in the last five years is -85% and that the central tendency is -30 to -40%. TURN also again compares SCE to SPS, noting that SCE's witness proposed a COR of $1.07/foot in Texas, but $3.52/foot for SCE, claiming that labor and other costs cannot explain this difference, and concluding that only errors in SCE's allocation process can explain this difference in full.[1011] SCE claims that there are five utilities reporting higher NSR than SCE and that California utilities are experiencing higher COR. SCE asserts that TURN's calculations of COR for SCE and SPS are inaccurate, but does not propose an alternative comparison. SCE argues that SPS's cost of new conductor is not high enough to be consistent with TURN's theory that SCE is overbooking to COR and underbooking to new installation.[1012]

For this Account, we adopt a gradual increase in NSR to -115%. While SCE's recorded data shows highly negative values, the evidence that SCE's allocation process is reasonable is inconclusive. Similarly, while SCE's recorded data is above the central tendency of the industry, there are other utilities recording much higher values.

21.3.9. Account 366 – Underground Conduit

SCE proposes an increase from –20% to -40%, noting five and ten-year averages of -125% and -108%. SCE claims its recommendation accounts for the high COR of vaults and manholes, which have been over represented in recent

[1010] ORA-23 at 39-40.
[1011] TURN-10 at 76-79.
[1012] SCE-26V3 at 116-120.

years.[1013] ORA recommends -22% because of SCE's "limited analysis."[1014] TURN proposes to retain the current -20%, citing concerns about SCE's allocation practices, industry data, and claiming that SCE's analysis of changes in the retirement mix is incomplete.[1015] SCE responds that its proposal is about one third of the most negative recent historical data and that 15 or more utilities have higher recorded NSR than SCE. SCE also notes that it proposes an increase in the life of assets in this account, and claims that this will increase NSR due to inflation and possibly other factors.[1016] We note that the four-year increase in ASL (from 55 to 59) explains only a small fraction SCE's proposed doubling of NSR, but it is a factor. SCE's recorded data and explanation of increasing life expectancy, which we adopt above, support an increase. However, SCE has not presented adequate quantitative analysis on the changing retirement mix to justify the full request. Therefore, we approve an increase to -30%.

21.3.10. Account 367 – Underground Conductor

SCE proposes an increase to -80% from the current -60%, noting five and ten-year averages of -162% and – 142%.[1017] ORA recommends no change, citing the 25% directive.[1018] TURN recommends a decrease to -50% claiming that SCE's showing is inadequate for an account of this size ($4.4 billion). TURN claims that SCE has not demonstrated that its allocation process is reasonable and that SCE allocates a higher proportion of costs to COR than does any other utility known to SCE's witness. TURN contends that circuit breakers have been over-represented in recent retirements, skewing NSR upward. TURN cites low COR for conductor because of economies of scale and abandonment in place.

[1013] SCE-10V3, Study at 94-95.
[1014] ORA-23 at 41.
[1015] TURN-10 at 80-81.
[1016] SCE-26V3 at 121-123.
[1017] SCE-10V3, Study at 95.
[1018] ORA-23 at 41-42.

TURN claims that SCE is an outlier, with a request five to eight times above the mean, median and mode of the industry, and 60% above the next highest NSR (-50%) in SCE's witness's direct experience.[1019] SCE claims there are nine companies in the industry database with higher recorded NSR than SCE and that it is therefore not an outlier. SCE claims that it initiated a new process in late 2013 to remove and replace conductor from conduit instead of abandoning the conduit underground, thus increasing the COR.[1020] However, we note that SCE's citation to the testimony of one of its T&D witnesses is an error; the correct citation is to the testimony of Roger Lee in SCE-3V4.

SCE's showing is not adequate to justify the requested increase. While the recorded data does suggest an increase, SCE has not made any specific showing that its allocation process is reasonable. While SCE's argument may be valid that replacing conductor may increase COR in the long term, it is uncertain the extent to which this change will occur. Further, it is clear that a change beginning in late 2013 cannot explain the trends seen in SCE's recorded NSR. SCE has not provided any significant analysis of the impact of the changing retirement mix. SCE has not met its burden of proof for this account, accordingly, we will retain the current -60% NSR.

21.3.11. Account 368 – Distribution Line Transformers

SCE recommends an increase from the current 0% NSR to -20%, noting five and ten-year averages of -48% and -27%.[1021] ORA recommends -2% noting that, aside from changed numbers, SCE's showing for this account is identical to Account 367.[1022] SCE's recorded data supports its proposed increase, and we adopt -20%.

[1019] TURN-10 at 81-84.
[1020] SCE-26V3 at 123-127 and SCE-3V4 at 31.
[1021] SCE-10V3, Study at 95-96.
[1022] ORA-23 at 42.

21.3.12. Account 369 – Services

SCE proposes an increase from -85% to -125%, citing five and ten-year averages of -431% and -244%[1023] ORA and TURN each recommend retaining the current NSR, arguing that SCE has not met its burden of proof. ORA cites industry medians around –60% and means from -74% to -166%. Excluding an outlier, ORA calculates a mean of -83% and claims that SCE has not complied with the 25% directive.[1024] TURN claims that underground services have only represented 30% of retirements in the last ten years, but account for 60% of the Account balance. Further, TURN suggests these underground services are likely to be abandoned in place. Finally, TURN claims that -85% is high relative to the recommendations of SCE's witness for other clients.[1025] SCE argues that its request is below the three-year industry mean, without excluding the outlier. SCE rejects TURN's retirement mix argument, calculating that even if underground services had 0% NSR, the account average NSR would be -172% assuming retirement mix equal to account balance.[1026] Although SCE's responses to ORA and TURN appear reasonable, SCE has not provided any detailed showing about future COR trends in this account. Consistent with gradualism, we adopt an increase to -100%.

21.3.13. Account 373 – Street Lighting

SCE proposes an increase from -20% to -40% based on five and ten-year averages of -87% and -77%. SCE claims that this recommendation does not account for the likely increase in NSR when it predicts more electroliers will be retired in the future relative to fixtures.[1027] ORA recommends -22% noting a

[1023] SCE-10V3, Study at 96.
[1024] ORA-23 at 42-44.
[1025] TURN-10 at 85-87.
[1026] SCE-26V3 at 128-130.
[1027] SCE-10V3, Study at 97-98.

three-year industry mean of -18%.[1028] SCE argues that ORA inappropriately excludes subaccounts from its industry calculation. Instead, SCE calculates three and five-year means of -166% and -74%.[1029] SCE's recorded data supports an increase, but due to the lack of specific analysis we only approve -30%.

21.3.14. Other Accounts and Summary

There are a number of other accounts for which no party contested SCE's showing. Unless otherwise noted above, SCE's proposals are approved. The following table shows a summary of the contested accounts.

Account	2012 GRC	SCE	ORA	TURN	Adopted
Transmission Plant					
352 - Structures and Improvements	-30%	-35%	-30%		-35%
353 - Station Equipment	-5%	-15%	-10%	-5%	-15%
354 - Towers and Fixtures	-70%	-100%	-70%	-40%	-60%
355 - Poles and Fixtures	-70%	-85%	-72%		-72%
356 - Overhead Conductors & Devices	-80%	-100%	-80%	-50%	-80%
Distribution Plant					
362 - Station Equipment	-20%	-30%	-20%	-20%	-25%
364 - Poles, Towers and Fixtures	-190%	-225%	-190%	-132%	-210%
365 - Overhead Conductors & Devices	-110%	-125%	-110%	-85%	-115%
366 - Underground Conduit	-20%	-40%	-22%	-20%	-30%
367 - Underground Conductors & Devices	-60%	-80%	-60%	-50%	-60%
368 - Life Transformers	0%	-20%	-2%		-20%
369 - Services	-85%	-125%	-85%	-85%	-100%
373 - Street Lighting & Signal Systems	-20%	-40%	-22%		-30%

21.4. Decommissioning Projects

21.4.1. SONGS Marine Mitigation

SCE proposes to retain the current 9.5-year remaining life, ending June 2022.[1030] This subject is addressed in Section 11.2.10 above.

[1028] ORA-23 at 44-45.
[1029] SCE-26V3 at 131.
[1030] SCE-10V2R1 at 32.

21.4.2. Mohave

SCE and ORA dispute the depreciation period for the remaining balance of the retired Mohave plant. SCE requests completing the depreciation in 2015, while ORA recommends completion in 2017.[1031] Both parties cite D.12-11-051 in support of their view. We agree with SCE that the intent of the "six years"[1032] in that decision was to end in 2015. Accordingly, we approve SCE's request.

21.4.3. Solar 2 and Mountainview Units 1&2

SCE has accrued more for decommissioning Solar 2 (by $2 million) and Mountainview 1&2 (by $8 million) than it spent. SCE proposes to refund the difference to ratepayers over the course of 2015 to 2017. No party opposes this proposal, we find it reasonable, and it is approved.

21.5. Generation Plant Service Life Estimates

SCE proposes no change to life spans for several generation assets: Hydro, Pebbly Beach, Mountainview, Peakers, and Solar Photovoltaic (PV). For Palo Verde, SCE proposes an increased life based on an extension of the plant's license.[1033] SCE's estimates are unchallenged for Hydro, Palo Verde, and Pebbly Beach. We find these unchallenged estimates reasonable, and they are approved. Parties propose different service lives for the remaining specific generation assets, as summarized in the table below.[1034]

TURN & ORA Service Life proposals for select generation plant (years)				
Generation Plant	**SCE**	**TURN**	**Δ**	**2015 Dep. Expense Δ (per JCE)**
Solar PV	20	30	10	($7.277 million)

[1031] ORA OB at 413.
[1032] D.12-11-051 at 653.
[1033] SCE-10 V3, Study at 23-27.
[1034] JCE V4 at issues ORA 284 and TURN 284.

Peakers	25	35	10	($5.990 million)
Mountainview	30	35	5	($4.462 million)
Generation Plant	**SCE**	**ORA**	**Δ**	**2015 Dep. Expense Δ (per JCE)**
Solar PV	20	25	5	($4.446 million)

For the Peakers, SCE notes that it has no retirement data and "estimates" a 25-year life.[1035] TURN contends that industry estimates for similar units are 30-40 years, anticipates new technology and low capacity factors for the units leading to long lives, and that SCE's workpapers appear to suggest a "30+ year life cycle prior to retirement."[1036] In rebuttal, SCE claims that increasing penetration of variable renewables will lead to increased start-ups of the units and that economic or regulatory factors may lead to earlier retirement.[1037] We agree with TURN, that SCE has not shown that the life of the Peakers is likely to be short relative to industry comparisons. We note that this Commission has approved energy storage and other approaches to address renewable variability in addition to the Peakers. TURN's 35-year life estimate is approved.

For Mountainview, TURN similarly proposes a 35-year life based on industry comparisons.[1038] SCE notes that, due to Mountainview's history, some equipment is older and was temporarily abandoned.[1039] We find TURN's estimate reasonable.

For Solar PV, ORA proposes to increase the service life by five years, based on a statement on SCE's website that PV systems should operate for more than 25

[1035] SCE-10 V3, Study at 26-27.
[1036] TURN-10 at 13-14.
[1037] SCE-26 V2 at 26-27.
[1038] TURN-10 at 14.
[1039] SCE-26 V2 at 27.

years.[1040] TURN proposes a ten-year increase based on an industry comparison, including "many" panel manufacturers' warranties are for 25 years. TURN also notes that SCE does not present a clear basis for its 20-year estimate.[1041] In response, SCE critiques TURN's comparison to another utility, but does not specifically respond to TURN's assertion about warranties or ORA's comments from SCE's website. On balance, we find that the 25-year life suggested by ORA is well supported by both TURN's and ORA's arguments, and adopt it.

22. Taxes

SCE forecasts $449 million (nominal$) in 2015 tax expense, comprised of income taxes ($197 million), payroll and miscellaneous taxes ($66 million) and property taxes ($186 million).[1042] Most elements of SCE's forecast are undisputed.

The contested issues relate to changes in accounting methods. SCE explains that, for ratemaking purposes, it incorporates changes in accounting methods in the first GRC after receiving "full approval" from the appropriate tax authority. SCE defines full approval as

> "the point where the Internal Revenue Service (IRS) has granted consent, where necessary, and the earlier of when the IRS has reviewed and agreed to the income adjustments of such method change or the point where in SCE's judgment the expected outcome of the income adjustments of such change can be measured with reasonable certainty."

SCE made three changes in accounting methods in this 2015 GRC relative to the 2012 GRC: 1) accelerated depreciation of streetlights to a seven-year life as assets without a class life, 2) accelerated depreciation of smart meters to a five-year life as computer systems, 3) and selecting a "safe harbor" method for

[1040] ORA -23 at 48.
[1041] TURN-10 at 14-15.
[1042] SCE-76 at 3. Note that this estimate was revised downward significantly relative to SCE's original forecast shown in SCE-10V2R1 at 34.

repair deductions of generation and T&D assets. SCE used the flow-through approach for each of these changes.[1043]

ORA does not contest SCE's tax forecast.[1044] TURN challenges SCE on two of these three changes: accelerated depreciation of smart meters and the safe harbor method for repairs.[1045]

First, as discussed in greater detail hereafter, we adopt a simple ratebase offset to offset the future tax expense related to the change in accounting for repair deductions. While our approach is superficially similar to TURN's the differences are important. In support of this outcome, we determine that this outcome is a prospective change, and not prohibited by retroactive ratemaking principles. Second, we adopt TURN's proposal on smart meter depreciation. Finally, we approve the uncontested elements of SCE's forecast, including the changes proposed after hearings in exhibit SCE-76, with certain conditions relative to those changes.

22.1. Background on Flow-Through vs. Normalized Tax Accounting

Both of the primary contested issues relate to accelerated depreciation of assets for tax purposes. In order to provide context for this change, we review flow-through and normalized tax accounting methods.

Under the flow-through method, income tax expense in each period recognized for ratemaking and regulatory purposes is the same as actual tax paid as to that tax year. Conversely, under the normalization method, income tax expense for *ratemaking* is based on the net income recognized for ratemaking accounting purposes in that period, regardless of when the taxes associated with

[1043] SCE-10V2R1 at 35-37.
[1044] ORA OB at 414.
[1045] TURN appears to conclude that ratepayers are indifferent or slightly better off because of the remaining change (streetlights).

that ratemaking income are actually paid. The flow-through method may be thought of as cash-basis accounting and the normalization method as accrual accounting.

In the case of accelerated depreciation, under a normalization approach, Accumulated Deferred Income Taxes (ADIT) is greater in early years while ratemaking tax expense exceeds actual tax paid. However, accelerated depreciation benefits eventually reverse as they decrease below the depreciation expense calculated under the straight-line approach. ADIT is drawn down in later years as actual tax paid exceeds ratemaking tax expense.

22.2. Safe Harbor Method for Repairs

TURN has challenged SCE's tax treatment of its repair costs for the years 2012, 2013, and 2014 in relation to forecast tax expense during test year 2015 and beyond. The rates for 2012-2014 were established by SCE's 2012 GRC proceeding, which ended in late November, 2012.[1046]

In August of 2012, SCE filed with the IRS its election of a "safe harbor" method of tax accounting for repair costs. That change was made available by regulations promulgated during 2011 in IRS Revenue Procedure 2011-43.[1047] The safe harbor method of accounting for repair deductions permits a taxpayer utility to apply a bright line rule for determining which of its repair costs are currently-deductible expenses and which are capital expenditures. In SCE's case, the election of the safe harbor method increased its current-year deductions. In other words, SCE elected to increase the amount of repair costs that were deductible for tax purposes in the year of the election, thereby reducing the amount of income taxes it paid for that year in comparison to the forecast taxes it discussed in its GRC filings and testimony. However, the reduction in 2012 tax

[1046] *See* D.12-11-051 at 613-24.
[1047] Rev. Proc. 2011-43, I.R.B. 2011-37, 326.

expense was magnified because Revenue Procedure 2011-43 essentially carried back the change in accounting method to prior tax years.[1048] Taxes in attrition years 2013 and 2014 were also reduced compared with the GRC forecast. As a result, SCE's shareholders received $321 million in savings during 2012-2014 relative to forecast tax expense. This tax savings equates to $542 million (nominal$) in revenue requirement if ratepayers had received those savings. Additionally, SCE ratepayers will pay $294 million (net present value, $741 million nominal$) of increased tax revenue requirement (including both increased book depreciation and a reduction in ADIT) from 2015 through 2042. For instance, the extra tax expense that would be paid by ratepayers in test year 2015 is $26.1 million.[1049]

SCE does not dispute TURN's quantification of the impact of its 2012-2014 tax filings on ratepayers and shareholders. We thus accept TURN's proposed values as conclusive for the purposes of this analysis.

In Comments on the Proposed Decision, SCE[1050] and SDG&E[1051] note that the Proposed Decision did not address the substantial ratepayer benefits ($580 million) of SCE's safe harbor repair deductions during tax years 2015-2017. We recognize that the benefits to ratepayers of SCE's election to use the safe harbor approach are real and we do not dispute SCE's election. However, like TURN,[1052] we see the repair deductions that occur during later tax years as distinct from those during 2012-2014. During each year of 2015-2017, ratepayers receive the tax deduction benefit of the safe harbor repairs made during that year; the lasting

[1048] *See* 26 U.S.C. § 481(a); Rev. Proc. 2011-43 § 7, App'x A.
[1049] TURN-5 at 103-106 and TURN-6 at Attachment 13.
[1050] SCE Comments at 14.
[1051] SDG&E Comments at 2-4.
[1052] TURN Reply Comments at 5.

effect (e.g. increased tax expenses) of prior year repair deductions is a separate issue.

After reviewing the evidentiary record of the 2012 GRC, it appears SCE never disclosed the existence of Revenue Procedure 2011-43 or any similar change in accounting method. SCE certainly did not include any substantive discussion of this new option in tax law in its 2012 GRC filing, testimony or other materials within the record. TURN alleges that SCE's shareholders improperly received the benefit of the increased deductions because SCE allocated the difference between forecast and actual tax paid accrued to SCE's shareholders during the 2011 through 2014 period, while SCE seeks in the current proceeding to assign the offsetting future increased tax expenses to ratepayers. Essentially, TURN claims that SCE received a windfall of rates based on taxes it did not actually have to pay during 2012 through 2014, and for which ratepayers will see increased costs in years 2015 and thereafter.

22.2.1. SCE Should Have Informed the Commission

TURN and SCE each devote considerable attention to the subject of if, when, and how SCE could have and should have informed the Commission of its election to use the safe harbor method.

Generally, SCE contends that its tax actions were appropriate. More specifically, SCE urges that it was not practical to inform the Commission during the 2012 GRC, noting that the change in tax policy only occurred in August of 2011, shortly before SCE's updated testimony was due. SCE further claims that there was significant uncertainty after that point as it undertook an analysis of the impacts of the change in tax policy.[1053]

[1053] SCE-26V2 at 36-42.

TURN, by contrast, contends that SCE could have and should have informed the Commission and parties to the 2012 GRC of the option for SCE to take the safe harbor election, as well as SCE's decision prior to the close of the record in the 2012 GRC to take that election. TURN also discusses similar changes in tax policy that occurred before Rev. Proc. 2011-43 and suggests that SCE has also inappropriately directed benefits of those changes to shareholders.[1054]

SCE's 2011 10-K filing, submitted to the United States Securities and Exchange Commission (SEC) in February of 2012,[1055] contained the following representation to the Securities and Exchange Commission and potential investors: "In August of 2011 the IRS issued guidance on repair deductions and changes in accounting method related to transmission and distribution assets. Based on this guidance, *SCE will include a second change in tax accounting method* in its 2011 tax return."[1056] SCE's 2011 10-K filing further explains "Due to the pending regulatory decision, SCE has not recognized an earnings benefit or regulatory asset related to this method change."

Our analysis is simple: it appears that at least a month before the publication of the 2011 10-K filing, SCE knew or should have known that it would make a change to its tax accounting method that would have a substantial impact on its revenue requirement. The proceeding remained open for nine

[1054] TURN OB at 281-289.

[1055] The Sections 13 or 15(d) Securities Exchange Act of 1934 require that large corporations whose shares are widely held must file under penalty of perjury an annual Form 10-K report with the SEC that provides the public and investment community with a comprehensive summary of a company's financial conditions and expected performance. Form 10-K filings ordinarily include information such as company history, organizational structure, executive compensation, equity, subsidiaries, pending business risks, and audited financial statements among other information that would be helpful for members of the public to determine the financial status of a business for investment purposes.

[1056] TURN-5 at 101, quoting SCE's 2011 Annual Report at 61. [Emphasis added.]

months following SCE's 10-K, leaving ten months for SCE to inform the Commission. During this time, SCE filed testimony, at least one motion and participated in multiple ex parte communications, but did not inform the Commission of this significant change in tax law applicable for the GRC period in question.[1057] The Commission's Rate Case Plan even expressly states that update testimony may include known changes such as changes in tax law.[1058]

SCE thus failed to notify this Commission of the new tax election option, as well as its decision during the pendency of the 2012 GRC proceeding to exercise that tax election that it knew would substantially reduce its tax liability for tax years 2011 through 2014. SCE was aware that this safe harbor tax election materially differed from its pleadings and testimony regarding estimated tax liabilities for the 2012 through 2014 GRC period. This omission of material information relevant to significant rate decisions by the Commission while the case remained open could constitute a violation of Rule 1.1 of this Commission's Rules of Practice and Procedure.[1059]

The Commission may open a separate proceeding to determine if and how to penalize SCE for this withholding of material information during an open

[1057] Notably, at least one of the ex parte communications discussed the relevant subject of post-test-year ratemaking. For more detail on the timeline, see Appendix B.

[1058] D.89-01-040, Appendix B.

[1059] Rule 1.1 of this Commission's Rules of Practice and Procedure reads in part "[a]ny person who signs a pleading or brief, enters an appearance, offers testimony at a hearing, or transac ts business with the Commission . . . agrees to . . . never to mislead the Commission . . . by an artifice or false statement of fact or law." The Commission's Rules of Practice and Procedure are available at http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&DocID=154622266. California Public Utilities Code, Section 2109 provides in part "In construing and enforcing the provisions of [Public Utilities Code sections] relating to penalties, the act, *omission, or failure* of any officer, agent, or employee of any public utility, acting within the scope of his official duties or employment, shall in every case be the act, *omission, or failure of such public utility*.

proceeding that resulted in an overstatement of tax expense and foreseeably produced a windfall to SCE's shareholders.[1060]

22.2.2. TURN's Proposed Remedy

TURN proposes "a relatively straightforward way to reverse" SCE's flow-through. TURN proposes a prospective ratebase offset, based on the normalization of the "excess" repair deductions during 2012-2014. Using this approach TURN calculates its proposed offset value of $293.118 million (mid-year, 2015). According to TURN, this change ensures that the benefits of the change in repair deduction are provided to ratepayers in the same proportion as the increased costs they bear. TURN calculates the net present value benefits to ratepayers of this change as $250.8 million, which it acknowledges is less than $294.3 million (net present value) of increased tax expenses ratepayers will bear in the future.[1061]

22.2.3. TURN's Proposal is Not Retroactive Ratemaking

22.2.3.1. Review of Precedents Cited by SCE

SCE asserts that TURN's recommendation constitutes retroactive ratemaking. SCE bases its argument on two Commission decisions, *SoCalGas*[1062] and *SoCal Water*,[1063] and on the California Supreme Court's holding in *Pacific Telephone*.[1064] TURN contends these decisions are distinguishable. We review the pertinence of these decisions.

[1060] *See Pacific Gas and Electric Company v. Public Utilities Comm., City of San Bruno et al., Real Parties in Interest*, 237 Cal. App. 4th 812, 845 (The CPUC "has the authority to impose monetary sanctions for disobedience of its orders made pursuant to the state's police power.").

[1061] TURN-5 at 107, TURN OB at 287.

[1062] *Re Southern California Gas Co.*, D.92-08-007, 1992 Cal. PUC LEXIS 532, 45 CPUC2d 256 (*SoCalGas*).

[1063] *Re Southern California Water Co.*, D.93-04-046, 1993 Cal. PUC LEXIS 223, 49 CPUC2d 60 (*SoCal Water*).

[1064] *Pac. Tel. and Tel. Co. v. Pub. Util. Comm'n*, 62 Cal. 2d 634 (*Pacific Telephone*).

In *SoCalGas*, the IRS had disallowed certain employee benefit expense deductions from 1983-1985 claimed by Southern California Gas Company (SoCalGas), and instead required the costs be capitalized. To track the disallowance, SoCalGas filed an advice letter to request authority to establish a memorandum account. SoCalGas argued that the adjustment was an "unexpected situation" because it comprised a "wholesale reversal of prior IRS policy."[1065] DRA and TURN, however, protested that the creation of the memorandum account was an impermissibly retroactive attempt at "truing up" tax expense.[1066] We noted DRA's argument that "[t]he same rule applies whether the amount at issue is an overcollection, resulting in windfall to the utility, or an undercollection."[1067] The Commission denied SoCalGas' request. We held "there can be no after-the-fact 'true-up' . . . unless the Commission specifically made provision for such an adjustment" previously.[1068] Furthermore, we explained that we do have the ability to address the future implications of tax strategies developed for past tax years.[1069]

One year later, the Commission relied on its *SoCalGas* decision to dispose of *SoCal Water*. In *SoCal Water*, the Southern California Water Company (SoCal Water) sought authority to institute a tax memorandum account to track payments resulting from an IRS audit. We noted that the facts were "virtually identical" to *SoCalGas*: "A claim was made that the IRS deficiency claim could not have been foreseen. The disputed tax matter had been part of a rate case."[1070] DRA protested that the memorandum account constituted retroactive ratemaking. The utility countered that there was no retroactivity because the

[1065] *SoCalGas* at *3.
[1066] *Id.* at *4.
[1067] *Id.* at *3-4.
[1068] *Id.* at *5.
[1069] *Id.* at *6.
[1070] *SoCal Water* at *11-12.

expenses had not yet been paid or incurred. We again denied the creation of a tax memorandum account. As earlier, we concluded that none of the considerations raised by the utility overcame "our mandate to set rate increases and rate reductions on a prospective basis."[1071] The Commission dismissed SoCal Water's argument that the potential IRS deficiency was a prospective cost as "sophistry."[1072] Although any back taxes and penalties were not yet due, any such deficiency would of course relate to previous tax years.

SCE contends that the facts in these cases are similar to TURN's proposal here, and recommends we reach a similar conclusion.[1073] TURN contends that the facts are not similar. As TURN explains, in each of these cases, the Commission was asked to change the authorized tax expense for past years for which prior GRCs had already set an authorized tax expense. Here, TURN proposes a prospective change in the revenue requirement for test year 2015 and beyond. SCE admits TURN's proposal is prospective only.[1074] This change has been discussed directly in the record of this proceeding, whereas the IRS changes in *SoCalGas* and *SoCal Water* were not addressed in the GRCs that set rates for the applicable years.[1075] We therefore do not believe TURN's proposal constitutes retroactive ratemaking.

Further, this approach is consistent with the California Supreme Court's holding in *Pacific Telephone*. In *Pacific Telephone*, the Court interpreted § 728 as embodying a rule against retroactive ratemaking. The Court found that "the Commission was empowered in GRC proceedings to set rates *prospectively* only, and that the Commission had overstepped its statutory power by ordering a

[1071] *Id.* at *12.
[1072] *Id.*
[1073] SCE-26V2 at 32-35.
[1074] TURN-70.
[1075] TURN OB at 294-296.

refund of previously approved rates after a Commission investigation had determined that these previously approved rates were too high."[1076] However, as the Court emphasized, the Commission shall determine rates to be in force after a hearing. Here, we have held hearings on the issue and set rates to be in force thereafter.

22.2.3.2. Analysis of Additional Case Law

Several other cases weigh into our consideration of SCE's flow-through of tax benefits to its shareholders starting in 2011 with proposed increased tax expenses to ratepayers in years 2015 and thereafter. In *So. Cal. Edison Co. v. Pub. Util. Comm'n* (*SCE II*),[1077] the California Supreme Court explained that California law has recognized that because "taxes are treated as part of a utility's cost of service, any tax savings should not be retained by the utility but should be immediately passed on to the utility's customers."[1078] Thus, "[a]ny savings acquired through the use of accelerated depreciation . . . is to be immediately flowed through to the ratepayers."[1079] Finally, quoting its decision a year earlier in *SCE I*,[1080] the Court emphasized that it is "elementary" that "the 'return' – i.e., the profit – of the utility is calculated solely on the rate base – i.e., the capital contributed by its investors; the utility is not entitled to earn an additional profit on its expenses."[1081]

SCE I specifically considered whether the Commission's attempts to remedy years of over-collection of rates to pay for fuel by SCE, expenses that did

[1076] SCE-26V2 at 35.
[1077] *So. Cal. Edison Co. v. Pub. Util. Comm'n*, 23 Cal. 3d 470 (1979) (*SCE II*).
[1078] 23 Cal.3d 470, 475.
[1079] *Id*. at 475, *citing Commission Investigation Regarding Rate Fixing Treatment for Accelerated Amortization and Depreciation for All Utilities,* 57 CPUC 598 (1960) *and Pacific Southwest Airlines* 73 CPUC 697, 708-10 (1972).
[1080] *So. Cal. Edison Co. v. Pub. Util. Comm'n*, 20 Cal .3d 813, 818-19 (1978) (*SCE I*).
[1081] *SCE II* at 476-77.

not ever accrue to the utility, constituted illegal retroactive ratemaking.[1082] There, the California Supreme Court upheld the Commission's remedy. Rather than "subjecting the utilities to the financial hardship of reducing that balance to zero in a single stroke, the commission adopted a proposal . . . of allowing the companies to gradually amortize the sum by monthly billing credits spread over a period of three years. That time span, the commission found, 'is a fair and reasonable initial time period over which to amortize such difference, without unduly burdening either the utility or the ratepayer.'"[1083]

The California Supreme Court has made clear that it is the duty of the Commission "to use any means legally at its disposal, including adjustment of rate of return, to insure that the savings [arising from a federal tax credit] were passed to the customers."[1084] Moreover, the Court has unanimously annulled a Commission decision that failed to consider an alternative method to flow through the benefits of a change in tax law to ratepayers.[1085] In light of the substantial and consistent case law, it is clear that the Commission would fail to regularly pursue its authority and abuse its discretion if it did not endeavor to mitigate the harm to ratepayers.

In *City of Los Angeles*, the Court "proposed alternative methods by which [a utility] could be prevented from benefiting from the collection of rates which, although lawful, were higher than necessary because they had made provision for tax expenses that did not materialize."[1086] To remedy the utility's overstated

[1082] *SCE I* at 815.
[1083] *Id.* at 824. Note that other electric utilities were also affected by the Commission's decision in *SCE II*, but only SCE sought judicial review. *Id.* at 824 n.14.
[1084] *SCE II* at 477, *quoting City of Los Angeles v. Pub. Util. Comm'n,* 15 Cal. 3d 680, 695, 704-05 & n.42 (1975).
[1085] *SCE I* at 477, *citing City and County of San Francisco v. Pub. Util. Comm'n*, 6 Cal. 3d 119, 129 (1971).
[1086] *SCE I* at 830.

tax expense, the Court unanimously held that the Commission could reduce future rates. Specifically, the Commission "could compensate for such past overcollections by the device of reducing the utilities' rates of return in the future: the commission could choose to mitigate the windfall accruing to the utilities . . . *by setting more modest rates of return* in recognition of the additional source of capital available to the utilities by virtue of the [change in] federal tax laws."[1087] The *SCE I* Court endorsed this analysis, stating that "[s]urely our unanimous opinion . . . would not have advised the adoption of an illegal procedure."[1088]

These conclusions were not dicta. SCE, then as now, raised the defense of the rule against retroactive ratemaking. The Court's analysis was therefore indispensable to establishing the Commission's authority to remedy past overcollections by one means or another. Presented again with overstated tax expense, a prospective adjustment is just as valid here as it was in *SCE I* and *City of Los Angeles*.

22.2.3.3. SCE's Conduct in Relation to the Retroactive Ratemaking Prohibition

Simply stated, a failure on our part to address the future costs of SCE's election would be a failure to uphold our obligation to just and reasonable rates under §451. Requiring ratepayers to bear the future costs of past tax benefits (or any other benefits or service) that they did not receive due to a lack of forthright presentation of material information by a utility is neither just nor reasonable.

[1087] *Id.* (original emphasis) (internal quotation marks omitted).

[1088] *Id.* at 831. Importantly, though SCE I centered on an adjustment clause that consisted of a mechanically-applied formula, City of Los Angeles was a consolidated review of three separate general rate cases. Therefore the SCE I Court's analysis is not limited to adjustment formulas; rather, the Court was reasoning that because prospective rate reductions were available for general rates in City of Los Angeles, it followed that such reductions were available for extraordinary rates. In City of Los Angeles, the prospective adjustment was the alternative.

SCE's conduct in the 2012 GRC makes any claim of retroactive ratemaking even less tenable than in *SCE I.* Here, the Commission was denied the opportunity to consider the appropriate treatment of the tax expense. In Comments on the Proposed Decision, SCE alleges that the "Wise Exception"[1089] has no application in this case.[1090] We disagree. Even though no finding of fraud has been made, this precedent is relevant given SCE's failure to inform the Commission of its election. California case law clearly establishes that a utility may not invoke the rule against retroactive ratemaking when the utility's own conduct has prevented the establishment of just and reasonable rates.

22.2.3.4. Other Factors

The mere fact that we consider past events in setting rates prospectively does not make this "retroactive ratemaking." In numerous portions of its application and testimony in this proceeding, SCE itself relies on discussion of past events, such as recorded costs, to justify its forecast of future costs. This is common practice, logical, and entirely appropriate. Thus, the common practice of looking to the past for guidance in predicting future costs of service is not "retroactive ratemaking."

22.2.4. A Ratebase Offset Does Not Violate IRS Normalization Rules

In its Opening Comments, SCE states that the rate base adjustment "is an impermissible flowthrough of part of the benefits of accelerated depreciation

[1089] *Wise v. Pacific Gas and Electric Company*, 77 Cal. App. 4th 287, 299-300 (1999) ("The rule against retroactive ratemaking is based on the presumption that the rate which was formally declared reasonable was considered and set in accordance with proper procedure. It is inconceivable that the Legislature intended the PUC would be powerless to award reparations where a public utility obtained a tariff rate by fraudulent means. Any other interpretation would fly in the face of the maxims of jurisprudence that '[n]o one can take advantage of his own wrong' [citation] and '[f]or every wrong there is a remedy' [citation].").

[1090] SCE Comments at 19.

prohibited by the normalization rules."[1091] It concludes that the adjustment constitutes a tax deferral for accelerated depreciation on costs that were never added to its depreciable basis.[1092] SCE threatens that if the Proposed Decision's adjustment for the Rev. Proc. 2011-43 election is adopted, it will seek an IRS ruling on whether the adjustment violates the normalization rules. We believe that any attempt to apply the normalization rules in this context is resolved by existing sources of tax law. The normalization rules are provided by Internal Revenue Code (IRC) section 168(i)(9), Treasury Regulations (Treas. Reg.) § 1.167(l)-1, and pertinent IRS rulings, which we now review and apply.

Section 168(f)(2) of the Internal Revenue Code (IRC) provides that a deduction for depreciation expense shall not be available for public utility property, as defined by IRC section 168(i)(10), if the utility does not employ a normalization method of accounting as described in IRC section 168(i)(9). IRC section 168(i)(9)(A) states a consistency requirement for the use of depreciation methods and requires the establishment of a tax deferral reserve. IRC section 168(i)(9)(B) describes a violation of these rules, while IRC section 168(i)(9)(C) provides the tax consequence for a violation.

Specifically, IRC section 168(i)(9)(A)(i) requires that the taxpayer, when computing tax expense for ratemaking purposes, including the establishment of its cost of service and regulated books of account, must use a method of

[1091] SCE Opening Cmt. on PD at 17. Presumably, "normalization" is used within the meaning of former section 167(l)(3)(G), former section 168(e)(3)(B), or current section 168(i)(9) of Title 26 of the U.S. Code.

[1092] SCE also asserts that the rate base adjustment must be a deferred tax because "[f]low-through items cannot create deferred taxes." We agree that repair deductions are flow-through, but reach a different conclusion: the rate base adjustment is not a deferred tax. SCE argues the adjustment must be a deferred tax because it is unrelated to the repair deductions, and it is unrelated to the repair deductions because the adjustment is a deferred tax. SCE's circular reasoning, lacking legal support, does not merit further analysis. See id. at 16.

depreciation with respect to its IRC section 168(i)(10) property that is the same as the method used for calculating its depreciation expense for such regulatory purposes and over a period no shorter than the period used for that depreciation expense. Under IRC section 168(a)(i)(9)(A)(ii), if there is a different amount available as a deduction under IRC sections 168 and 167 when applying the same calculation method as under IRC section 168(a)(9)(A)(i), then the taxpayer must reflect that difference in a tax deferral reserve. IRC section 168(a)(9)(B) requires that the procedures of subparagraph (A) are in fact applied, which includes the consistent use of forecasts.

Treas. Reg. § 1.167(l) provides the normalization regulations. These regulations do not relate to other book-tax timing differences other than federal accelerated depreciation.[1093] Treas. Reg. § 1.167(l)-1(h)(2)(i) requires that deferred income tax based on actual tax liability shall be credited to a reserve for deferred taxes. Treas. Reg. § 1.167(l)-1(h)(1)(iii) provides that the amount of deferred income tax is the "excess . . . of the amount the tax liability would have been had a subsection (l) method been used over the amount of the actual tax liability."[1094] A subsection (l) method includes the straight-line method of depreciation used here for ratemaking purposes.

SCE argues the normalization rules should apply because the adjustment, it alleges, consists of "additional deferred taxes."[1095] However, SCE's characterization of "additional deferred taxes" is inconsistent with the normalization rules. Treas. Reg. § 1.167(l)-1(h)(1)(iii) provides that deferred taxes are calculated with respect to "actual" tax liability, but SCE defines deferred

[1093] Treas. Reg. § 1.167(l)-1(a)(1) ("The normalization requirements . . . pertain only to the deferral of Federal income tax liability resulting from the use of an accelerated method of depreciation").
[1094] Emphasis added.
[1095] SCE Comments at 16.

taxes with respect to the depreciation "that would have resulted" if it did not make the Rev. Proc. 2011-43 election.[1096] Rev. Proc. 2011-43 permits an electric utility to recognize current-year business expense deductions for amounts that would have been capitalized but for the safe harbor election.[1097] In other words, SCE's "additional deferred taxes" depend on depreciation "that would have resulted" if SCE had more depreciable basis than it in fact had. That addition to basis never occurred, and therefore the rate base adjustment cannot be a tax deferral. As SDG&E correctly states, "normalization [of repair cost expenses] is not required under the federal tax law."[1098]

In contrast, this decision is consistent with Treas. Reg. § 1.167(l)-1(h)(1)(iii). As stated previously, the deferred taxes reflected on SCE's regulatory books of account are based on the differences between SCE's regulatory tax liability and its actual tax liability, as calculated on its actual depreciable basis and consistent with IRC section 168(i)(9)(A)(i). Because the final rate base adjustment is not based on SCE's actual or regulatory depreciation, it follows that the rate base adjustment for the increase in future tax expense cannot invoke the normalization rules.

Our conclusion is bolstered by SCE's conspicuous failure to cite to any legal authority except for oblique references to "normalization rules." Moreover, neither Congress nor the IRS has indicated that a taxpayer utility is entitled to depreciation deductions for expenditures for which there was never an increase in depreciable basis. This is unsurprising. SCE's logic would entitle it to effectively understate its gross income, first by electing to treat repair expenses as increases in current-year deductions under IRC section 162 and Rev. Proc.

[1096] SCE Comments at 16.
[1097] Rev. Proc. 2011-43 section 2.01 ("expenditures are deductible as repairs under § 162 or must be capitalized as improvements under § 263(a)") (emphasis added).
[1098] SDG&E Comments at 14.

2011-43, and then by treating those same expenses as increases to depreciable basis under IRC sections 263 and 1016. There is no principled reason why SCE should receive the benefits of both a current-year expense deduction and a depreciation deduction for the same repair costs. A taxpayer cannot receive a tax benefit twice.[1099] Likewise, SCE cannot interpret the tax code as though it possessed additions to depreciable basis that it elected to forego.[1100]

A closer inspection of Rev. Proc. 2011-43 and the depreciation and basis rules also demonstrates that the rate base adjustment is not a deferred tax. Section 2.02 of Appendix A of Rev. Proc. 2011-43 provides the calculation methodology for the IRC section 481(a) adjustment. Section 2.02(4) specifically provides that the "basis of electric transmission and distribution property calculated after taking into account the repair deduction basis adjustment [for extrapolation]" shall be the basis for adjustments that must be made "before any depreciation is computed." The basis rules stated in Section 2.02(4) are thus consistent with Rev. Proc. 2011-43's treatment of repair costs as either "deductible as repairs under § 162 or . . .capitalized as improvements under § 263(a)." Rev. Proc. 2011-43 therefore distinguishes in two different ways those costs to be recognized as current-year deductions under the safe harbor and those costs to be capitalized and later taken into account as IRC section 1016(a)(2) and (3) adjustments.

[1099] The Ilfeld doctrine, as interpreted by Skelly Oil, requires that tax laws be interpreted to deny a double tax benefit unless a statute or regulation specifically authorizes it. See Ilfeld Co. v. Hernandez, 292 U.S. 62 (1934); United States v. Skelly Oil Co., 394 U.S. 678 (1969). Tax regulations also prohibit double deductions or their equivalent. See Treas. Reg. § 1.1016-6(a) (basis adjustments "to eliminate double deductions or their equivalent."); see also Treas. Reg. §§ 1.161-1, 1.212-1(o) ("Double deductions are not permitted.").

[1100] Taxpayers have a duty to treat items consistently. See Unvert v. Commissioner, 72 T.C. 807, 814 (T.C. 1979) ("'there is a duty of consistency as to [tax] treatment, and one should be held to the consequences of the initial treatment.'").

This differential treatment of currently-deductible and capitalized costs may be stated with greater precision. Specifically, IRC section 1016 adjustments result in the IRC section 1011 adjusted basis, which in turn provides depreciable basis under IRC section 167(c). It is accelerated depreciation derived from that depreciable basis which must be normalized. Neither that basis nor the resultant depreciation deductions are reduced by the rate base adjustment.[1101] Congruently, the full amount of those accelerated depreciation deductions has been normalized by this proceeding. Because the rate base adjustment does not interact with any of these components of accelerated depreciation, it is not a deferred tax.

Finally, the error in SCE's argument may also be demonstrated by a simple hypothetical. If, for example, SCE employed straight-line depreciation for both its actual and regulatory tax expense, a tax deferral for accelerated depreciation would never arise, consistent with IRC section 168(a)(i)(9)(A)(ii). But if SCE concealed a tax election (under Rev. Proc. 2011-43 or similar authority) that increased its repair deductions, the Commission could nevertheless order a rate base adjustment to compensate for the undisclosed decrease in depreciable basis. Given the absence of accelerated depreciation, it would be obvious that the rate base adjustment was not "additional deferred taxes." To use SCE's phraseology, the "difference between [actual] accelerated and [actual] book depreciation times the tax rate" would be zero because there are not different applicable depreciation methods.[1102] The same logic applies to the facts of this proceeding: the rate base adjustment is not contingent upon the existence of accelerated depreciation.

[1101] The IRC section 481(a) adjustment merely carries backward the safe harbor election, and therefore the underlying principles for basis adjustments should apply generally to the safe harbor deductions.

[1102] SCE Comments at 16.

SCE is receiving the full benefits of accelerated depreciation, as calculated on its actual depreciable basis. There is no amount of accelerated depreciation that will not be normalized. SCE has attempted to mischaracterize this adjustment as a deferred tax, even though it does not deny SCE the full amount of the tax deferral as calculated under Treas. Reg. § 1.167(l)-1(h)(1)(iii) and (h)(2)(i), and even though Treas. Reg. § 1.167(l) only applies to accelerated depreciation. The rate base adjustment merely corrects for an unforecasted increase in tax expense that resulted from SCE's undisclosed tax election. Accordingly, we believe our approach is consistent with the normalization rules because it is entirely unrelated.

However, we fully intend that SCE comply with the normalization rules. While we believe we have reached the correct result, and though SCE has not cited to any written determination, case, regulation, or statute to support its position, we recognize that SCE might later obtain a ruling from the IRS. Accordingly, SCE may track changes in revenue resulting from the rate base adjustment in the Tax Accounting Memorandum Account adopted in Section 22.6 below. If SCE decides to request an IRS letter ruling, SCE shall file and serve a copy of its request to the IRS as a Tier 1 Advice Letter at least 30 days *before* sending the request to the IRS. In the event that SCE receives a relevant IRS ruling contradicting this decision, then it shall comply with the IRS's interpretation of the applicable tax laws by filing a Tier 2 advice letter with this Commission to seek an appropriate adjustment to its revenue requirement and/or rate base.

22.2.5. Adopted Remedy

We agree in principle with TURN that it is inequitable that ratepayers are burdened prospectively with the higher subsequent year tax requirements

associated with the tax change, particularly since ratepayers received no corresponding recognition of the initial savings from the tax change at the time of SCE's election. In the interests of consistency in ratemaking treatment, the prospective tax treatment of repair deductions for ratemaking purposes should be consistent with the assumptions that applied for ratemaking purposes when the applicable repair costs were incurred. By contrast, SCE's proposed ratemaking treatment creates inconsistencies in applying the effects of the change for ratemaking tax purposes (a) initially, at the time of the initial tax deduction recognition and (b) during subsequent years' recognition of the effects of those deductions for ratemaking purposes. By applying SCE's different ratemaking assumptions, shareholders won at the front end, while ratepayers lose at the back end of the chain of tax timing adjustments for ratemaking purposes.

Although SCE claims that TURN's proposal (and the ALJ's variation thereof, as described below) invoke retroactive ratemaking, SCE's own proposed treatment also involves a prospective ratemaking tax requirement based on past actions (i.e., SCE's election to change its repair deduction treatment). Under either proposal, prospective tax obligations and timing differences must be determined, in part, as a byproduct of 2011-2014 vintage repair costs. Under either approach, we must set prospective tax requirements based on ratemaking assumptions concerning past tax elections and rules. The defining difference between SCE and TURN, however, more pointedly is whether we apply ratemaking assumptions going forward for purposes of assigning ratepayer obligations for the treatment of repair cost deductions that are consistent and fair in comparison with the ratemaking assumptions that applied when the applicable repair costs were originally incurred.

There is no basis for claims that it would constitute retroactive ratemaking merely to shield ratepayers from paying higher future tax obligations that result from past tax savings that ratepayers never saw. We decline, however, to adopt TURN's proposed remedy and instead adopt an approach inspired by TURN's concerns about equity. Rather than look to past repair deductions, we instead look to the net present value of future excess costs to ratepayers resulting from SCE's proposed ratemaking tax treatment for the repair deductions as compared with the ratemaking tax treatment assumptions in place at the time of the applicable repairs. A reduction of $294.358 million is required in comparison to SCE's proposed ratemaking treatment.

This reduction represents the additional future excess cost, in net present value terms, that would be faced by ratepayers associated with funding higher prospective tax provisions under SCE's approach. Yet burdening ratepayers with these higher tax provisions would be inconsistent with the ratemaking assumptions underlying the tax treatment of the initial repair costs.

However, as TURN observes, under TURN's own proposal ratepayers would only recoup $250.8 million (net present value) of that extra cost.[1103] For our approach we calculate a ratebase offset of $344.026 million as necessary to achieve a net present value benefit to ratepayers equal to their increased future costs attributable to SCE's election. This calculation assumes the same ratio of benefits to the ratebase offset as calculated by TURN. By adopting this value as a ratebase offset, ratepayers would be indifferent to SCE's election, in TURN's calculation. Ratepayers did not get the benefit of SCE's election during 2012 to 2014. While we do not adjust rates retroactively to change that outcome, we will apply a prospective ratemaking treatment so that ratepayers are not forced to pay

[1103] TURN-5 at 107.

prospectively for the effects of past tax benefits that they never received. Instead, applying our adopted adjustment, ratepayers will, in effect, not pay the prospective additional costs of that election relating to ratemaking tax provisions for the period 2015 and beyond. Therefore, we adopt a ratebase offset of $344.026 million, applied initially in 2015.

We implement this ratebase offset in a different manner than in the Proposed Decision. In the RO model supporting this decision, the offset is implemented as a direct line item adjustment to ratebase, independent of other factors. The ratebase offset in turn impacts other revenue-dependent portions of the model (e.g. taxes, franchise requirements). The value of the offset is amortized (on a straight line basis) over the course of 27 years (2016 to 2042). The direct net present value of benefits to ratepayers of this change, implemented in the full context of this decision, is approximately $~~265~~305 million on a total company basis or $~~249~~287 million on a CPUC-jurisdictional basis. Thus, even though the direct impact of this ratebase offset is lower than calculated in the Proposed Decision, we believe it is a reasonable amount to compensate ratepayers for the increased future costs that they will bear.

22.3. Advanced Meters

TURN contests SCE's state income tax treatment of smart meters (also called advanced meters, a component of Advanced Metering Infrastructure or AMI). Specifically, TURN recommends reducing SCE's state income tax forecast by $2.090 million, less a $0.731 million increase in federal taxes per year during 2015-2017. In TURN's view, SCE inappropriately changed the tax depreciation schedule of advanced meters installed during 2012 after the AMI Balancing Account was closed at the end of 2012. TURN calculates that as a result of SCE's change, ratepayers would pay 100% of the costs of these meters, but receive only

66% of the state tax depreciation. TURN notes that, although the smart meter change is very similar to the change in streetlights, TURN does not contest the change for streetlights because there is a net present value benefit to ratepayers in that instance.[1104]

SCE replies that TURN's proposal would require SCE to return revenue approved earlier[1105] and is retroactive ratemaking, citing *SoCalGas* and *SoCal Water*. SCE claims that its accounting actions follow regulatory guidance in D.08-09-039 (use actual amounts through 2012 in the AMI Balancing Account) and D.12-11-051 (use forecasts for 2013 and 2014 in general rates). 2015 rates would reflect the most current information via SCE's forecasts in this proceeding.[1106]

This situation is materially similar to the previous discussion of the safe harbor repair mechanism. This is our first opportunity to review this change, and TURN asks us to set rates prospectively. SCE does not challenge TURN's calculation of the tax and revenue requirement impacts. Accordingly, we adopt TURN's recommended $1.359 million net reduction in tax expense.

22.4. Updates to Tax Forecast in Exhibit SCE-76

As discussed in the procedural background, SCE submitted exhibit SCE-76 by motion on May 11, 2015. The ALJ ordered an additional exhibit addressing certain questions (SCE-78) and later admitted both exhibits into evidence.

This testimony makes two significant decreases to SCE's forecast revenue requirement: 1) a revised estimate of tax repair deductions attributable to Pole Programs in 2015-2017, and 2) a changed formula to allocate tax expense between

[1104] TURN-5 at 108-110.
[1105] In D.12-11-051, AL 2832-E, and AL 2961-E.
[1106] SCE-26V2 at 44-45.

FERC and CPUC jurisdictions. The combined test year 2015 revenue requirement change is $201 million; the amount is higher in 2016 and 2017.

Generally, SCE explains that it discovered a "unique repair-eligible" profile of pole expenditures while preparing and reviewing its 2014 financial statements. As discussed in Sections 7.6 and 7.7 above, SCE requests, and we approve (albeit at a lower level), significant increases in pole expenditures in this decision. Thus, the impact of this repair-eligible profile is significant in the larger context of this case. Similarly, SCE explains that the increased spending on poles and related deductions is a key driver of book tax timing differences. In CPUC jurisdiction, the deductions are flow-through, but normalized under FERC jurisdiction. The increase in pole deductions causes a difference relative to SCE's previous assumption (book tax timing differences are allocated according to the overall rate base allocation).[1107]

No party opposed SCE's motion to admit SCE-76 or the position SCE took in either of these exhibits. However, ORA and TURN jointly note the following points in their response to SCE's motion: 1) some or all of the revenue requirement reductions may have been captured by SCE's proposed balancing account covering pole programs, 2) the net benefits to ratepayers of the alternative allocation depend on the level of offsetting costs in FERC rates, and 3) SCE's changes do not impact any party's position on other disputed issues in this proceeding.

In response to the ALJ ruling, SCE further explains that the revenue requirement reductions will not result in *any* offsetting cost increase to ratepayers (FERC-jurisdiction included) during this GRC period. SCE estimates a net present value of benefits during this GRC period of $598 million.[1108]

[1107] SCE-76.
[1108] SCE-78.

Like TURN and ORA, we appreciate SCE's efforts to bring this information to our attention early. This effort appears consistent with our desire for candid and timely information discussed elsewhere in this tax chapter.

While SCE did not present analysis of periods further into the future, any net cost increases in those future periods would need to be strongly adverse to ratepayer interests to offset the $598 million net present value benefits in this GRC period. Accordingly, we find it reasonable to adopt SCE's proposed adjustments in the tax expense forecast in this GRC. Nevertheless, we must be cognizant of the possibility that future costs may outweigh benefits, even on a net present value basis. SCE's exceptionally narrow reading of the phrase "taking into account future periods" in the ALJ ruling[1109] does not help our confidence that there is no unpleasant surprise lurking around the corner in 2018 or beyond. Therefore, we require that SCE present a net present value estimate of these tax changes, as measured from 2015, in its next GRC. That estimate should take into account the entire tax lives of the relevant depreciable assets. Stated differently, this estimate should take into account sufficient future periods that considering *further* future periods would have no material impact on the outcome of the analysis. If the Commission's estimate of the net present value of these changes, as measured from 2015, is a net cost to ratepayers, that finding may be used as the basis to compensate ratepayers for those increased costs.

22.5. Other Issues

SCE proposes an Employee Stock Ownership Plan (ESOP) Tax Memorandum Account (ESOPTMA) to track to track any differences in the

[1109] In SCE-78, SCE remarkably limits its analysis of "future periods" to 2015-2017, despite other subparts of the same question referring to "the time period covered by this GRC" which is also 2015-2017. The phrasing of the "future periods" question even implicitly acknowledges the possibility that peering further into the future than this GRC may increase uncertainty with the phrase "To a reasonable approximation."

ratemaking tax treatment of dividend deductions that arise due to proposed treasury regulations.[1110] ORA opposes this proposal, noting that we denied this request in the 2012 GRC.[1111] The basic elements of this situation are unchanged since 2012, the proposed regulations have been pending, but not finalized, for several years. In the event that they become final during this rate case period, SCE may file a Tier 3 Advice Letter under the Z-factor mechanism to address this change in revenue requirement.

22.6. Policy Considerations

TURN's language strongly condemns SCE's actions with respect to its tax accounting changes. We do not review these arguments in detail. Nevertheless, we note that allowing SCE to use the prohibition against retroactive ratemaking as a shield, after not clearly calling the underlying change in accounting methods to our attention in the prior GRC, would be a strikingly poor precedent. We decline to take any action that might give utilities an incentive to withhold relevant information from us in the future.[1112] Candid utility testimony on the subjects of cost and accounting is of paramount importance to the proper completion of our ratesetting duties.

Further, we note that SCE's post-test-year ratemaking (PTYR) mechanism, discussed in Section 19 above, also includes a "Z-factor" mechanism designed to address material changes to costs between rate cases. No party used the Z-factor approach to bring SCE's tax accounting changes to our attention, and thus address the change earlier. As we have previously stated, SCE is responsible for reporting both positive and negative Z-factors.[1113] Handling such changes earlier

[1110] SCE-10V2R1 at 43, SCE-10V1R1 at 50-51.
[1111] ORA-22 at 2.
[1112] *See Wise, 77 Cal. App. 4th at 300 ("a remedy for the wrong committed and hopefully, serve to deter such fraudulent conduct in the future.").*
[1113] *See* D.94-06-011, 55 CPUC2d 1, at *102.

may lead to lower levels of controversy and potentially more collaborative solutions. In comments on the Proposed Decision, SCE contends that its election to select the Safe Harbor method was ineligible for Z-factor treatment because SCE management exercised discretion in making the election. SCE also contends that the specific additional requirements in the Proposed Decision for SCE to provide notice of major changes are "unworkable." SCE proposes two alternative solutions: a two-way memorandum account and a change to a full normalization policy.[1114]

First, while we agree with SCE that a full normalization policy may have avoided the contentious litigation of tax issues in this GRC, we do not have a record in this proceeding on which to base any general conclusions about the merits of such an approach. Second, we accept SCE's point that a simple memorandum account approach is most appropriate for this GRC period. We may consider more specific approaches in the future, and welcome such proposals from parties in the next GRC or other appropriate proceedings. Therefore, SCE shall create a two-way Tax Accounting Memorandum Account to track all tax changes during this GRC period.

Although we do not adopt specific criteria for when SCE must bring accounting changes to our attention directly (beyond simply recording them in the Tax Accounting Memorandum Account) we wish to send a clear signal to SCE in favor of prompt disclosure. We expect SCE to bring to our attention any major changes in tax accounting at least as soon as it notifies the SEC, investors, or other public agencies. SCE need not have precise calculations of the revenue requirement impacts in order to alert this Commission of such changes. Failure

[1114] SCE Comments at 19-22.

to disclose such changes in a timely fashion undermines the integrity of the regulatory process and may be found to be a violation of Rule 1.

Moreover, we note that in a separate post-hearing exhibit, SCE describes the impact of the Tax Increase Prevention Act of 2014. In addition to revenue requirement reductions and other changes in 2015, SCE notes a 2014 tax depreciation increase of $874 million.[1115] SCE does not elaborate on the impacts of this change, and no other party addresses it. Importantly, it is unclear from the record before us whether benefits of the tax change were flowed-through to shareholders in 2014 in exchange for long-term cost increases to ratepayers. In the 2018 GRC, parties should address this subject, if it has not been addressed in another way sooner. SCE shall include the 2015-2017 impacts of this change in the Tax Accounting Memorandum Account.

23. Rate Base

Rate Base is the net investment value on which SCE's return is determined. Rate Base represents the depreciated value of assets in service. The components of rate base include: fixed capital, adjustments, working capital, and deductions for reserves.[1116]

In addition to the specific issues addressed below, note that there is an offset to Rate Base adopted in Section 22 above.

23.1. Customer Advances

Customer advances for construction are an adjustment to rate base representing refundable amounts provided by applicants (generally developers) before SCE constructs distribution facilities according to Tariff Rule 15. SCE does not pay interest on these advances, and they are an offset to rate base. Advances not refunded within ten years are treated as CIAC, an offset to Plant-In-Service.

[1115] SCE-74 at 2-3.
[1116] SCE-10V2R1 at 52-54.

For electrical services, SCE forecasts a decline in the balance of customer advances along with an increase in meter sets (which typically trigger refund of advances). For inflows, SCE forecasts $280 (2012$) in new advances per meter set based on a 2008-2012 average. SCE used a 5YA to forecast the small temporary services component of customer advances.[1117]

ORA forecasts a higher balance than SCE. ORA proposes using a three-year (2010-2012) average of $353 per meter, which it contends "accurately reflects current economic conditions."[1118]

TURN applies the difference between SCE's 2013 forecast and 2013 actual to SCE's 2014 and 2015 forecasts, resulting in a higher forecast. For temporary services, TURN proposes a four-year (2010-2013) average that is lower than SCE's forecast, noting that 2013 actual was lower than SCE's forecast.[1119]

SCE contends that ORA's position is unsupported and inconsistent with ORA's arguments in the 2012 GRC.

SCE also rejects TURN's adjustment, contending that a forecast-actual variance in one year does not indicate such a variance in later years and that it would be unreasonable to rely on a single year's variance. SCE analyzes historical data in support of its arguments.

Finally, SCE notes that both TURN and ORA argue for lower meter set forecasts, but do not propose to assume lower meter sets for purposes of this calculation. SCE cites D.89-12-057 in support of its position.[1120]

TURN observes that SCE's rebuttal explains the inflow (i.e., new customer advance receipts), it does not explain the error in outflow (refunds) during 2013. TURN also contends that SCE's analysis of historical data is misleading by

[1117] SCE-10V2R1 at 54-57.
[1118] ORA-24 at 4-6.
[1119] TURN-5 at 124-125.
[1120] SCE-26V2 at 46-51.

comparing end of year and average year forecasts. TURN concludes that error in the 2013 forecast must be considered in developing the 2015 forecast.[1121]

There is considerable variation in the year-to-year trend in customer advances, and SCE's five-year average forecast method is appropriate. Further, in Section 16 above, we adopt TURN's lower meter set forecast and decline to implicitly assume higher meter set levels reasonable here. Nevertheless, TURN's argument that SCE has not explained the variance between 2013 forecast and 2013 actual refunds is compelling. We agree with TURN that some adjustment based on 2013 actual is appropriate, and that TURN's proposal to "shift" 2015 upward by the amount of the variance in 2013 is reasonable. TURN's approach preserves the five-year average based forecast. Therefore, we adopt TURN's forecast.

23.2. Materials and Supplies

Materials and Supplies (M&S) inventory is maintained to facilitate capital and O&M activities, both on an emergency and planned basis. From 2008 to 2012, M&S grew at a compound annual rate of 5.4%. SCE forecasts a compound annual growth of -0.4% from 2013 to 2017. SCE explains these trends as driven by increase in T&D activity, followed by improved inventory management processes. SCE's M&S balance is divided into three categories: T&D, generation, and IT/transportation.

For T&D, M&S including poles, conductor, and switches are stored at over 100 locations across SCE's service territory. SCE finds a strong correlation between expenditures and inventory (R-square of 0.89) showing $55,000 in inventory to support $1 million in incremental T&D construction. SCE applies this relationship to its forecast T&D expenditures (excluding two major

[1121] TURN OB 299-302.

transmission projects) to calculate its forecast. For this component, SCE forecasts a compound growth rate of 7.5%.

For generation, SCE forecasts a -1.1% compound growth rate and 2.6% for IT/transportation. Further, SCE makes adjustments to M&S for liabilities including unpaid sales taxes as well as Operational Excellence.[1122]

ORA contests SCE's T&D M&S forecast, recommending $40,000 in inventory per $1 million in T&D expenditures. ORA cites the two most recent GRC decisions in support of this relationship. ORA does not contest the other components of SCE's forecast.[1123]

In rebuttal, SCE observes that: ORA provides no regression or other analysis in support of its proposed relationship, that SCE's regression analysis is the same as that used in the two decisions cited by ORA, and that the correlation appears stronger including 2013 data (0.90) than ending with 2012 data.[1124]

We agree with SCE that ORA's proposal is unsubstantiated. SCE's regression analysis of T&D M&S is consistent with those approved in past decisions, shows a strong correlation, and is, thus, reasonable. However, as in the last GRC, we find it reasonable to apply the M&S forecast approach to the adopted capital expenditures instead of SCE's forecast. Therefore, we reduce the T&D M&S forecast by 10%, for a total M&S forecast of $116.948 million (nominal$) in 2015.

23.3. Working Cash – Operational Cash

Working cash (also called cash working capital) is supplied by shareholders to bridge the gap between the time expenditures are made and the

[1122] SCE-10V2R1 at 57-66.
[1123] ORA-24 at 7-8.
[1124] SCE-26V2 at 51-55.

time revenues are received. SCE follows the lead lag approach[1125] to calculate working cash.[1126]

Operational cash is a component of working cash representing the average balance of funds supplied by investors to meet daily needs in non-interest bearing accounts. Operational cash includes cash-bank balances, special deposits related to relocation, working funds, prepayments for rents and other costs, gas option premiums to hedge price risk, and other accounts receivable. Certain deductions are also included for liabilities, such as paid time off, user taxes, and workers compensation reserve.[1127]

ORA recommends that cash balances in bank accounts be excluded from rate base, citing SCE's 2006 and 2009 GRC decisions as precedent.[1128]

SCE contends that, although the $6 million balance at issue is not required explicitly by its banks, it is practically required by virtue of timing of payments compared to investment deadlines.[1129]

The same arguments were at the center of the dispute in the prior GRC and we reach the same conclusion here.[1130] We find it reasonable to strictly interpret Standard Practice U-16 so that SCE has an incentive to manage its cash as effectively as possible.

TURN makes a number of recommendations related to operational cash, which SCE accepts on rebuttal. SCE agrees to remove $5.7 million from rate base if Long-Term Incentive Plan (LTIP) is denied.[1131] LTIP is denied in Section 10.3 above, and we accordingly remove this amount from working cash.

[1125] See Standard Practice U-16.
[1126] SCE-10V2R1 at 67-68.
[1127] SCE-10V2R1 at 68-73.
[1128] ORA-24 at 10.
[1129] SCE-26V2 at 57-58.
[1130] See: D.12-11-051 at 635.
[1131] SCE-26V2 at 58-59; TURN OB at 302.

With the exception of these two adjustments, SCE's operational cash forecast is undisputed and is reasonable.

23.4. Working Cash – Lead Lag Study

SCE describes many parameters of its lead lag study, but some of the details are confidential. SCE's revenue lag estimate is 44.6 days, an increase from the prior GRC driven by new requirements related to customer disconnections and the poor economy. For expense lag, SCE calculates an average of 45.93 days for a subset of expenses that are not confidential.[1132]

ORA proposes different numbers of lag days for state and federal income taxes, based on applying an average of 2008, 2009, and 2011, compared to SCE's 2008-2012 five-year averages. ORA explains that 2010 was "uncharacteristic" because of tax refunds, but does not address 2012.[1133]

TURN contends that an arithmetic average of the income tax lag days, as proposed by SCE, is "not representative of anything" given the variability of SCE's actual tax payments. TURN argues that SCE forecasts paying significant federal income taxes in 2015, and that this is a very different circumstance to recent years when tax liability was low or even negative. For instance, TURN observes that a negative number as in 2010, when SCE received a net refund, will not recur. Further, TURN argues that it is inappropriate to include 2012 as a zero lag-day data point on the basis that no taxes were paid. Therefore, TURN argues, a weighted average of 2008-2009, when SCE paid significant income taxes, is appropriate for federal income tax. For state taxes, TURN recommends a five-year weighted average. TURN's proposal leads to a $123.528 million difference in rate base, compared to SCE.[1134]

[1132] SCE-10V2R1 at 72-82.
[1133] ORA-24 at 11-12.
[1134] TURN-5 at 129-132.

SCE responds that ORA and TURN's proposals on income tax lag days are arbitrary and unsupported. SCE notes that it paid no taxes or received refunds in six years during 2002-2012, and that these years are not anomalies and should not be excluded. SCE cites the 2009 GRC decision as precedent.[1135]

As TURN observes in its brief,[1136] the 2012 GRC decision reached a different conclusion than in 2009, finding that it was appropriate to exclude certain years as non-representative.[1137] We agree with TURN that years with minimal or negative tax payments may not be indicative of 2015; these years should not be unduly weighted. However, we also see merit in having a consistent approach to this calculation from GRC to GRC. On balance, we find that a five-year weighted average, as proposed by TURN for state income tax, is reasonable for both state and federal. This approach appropriately places more emphasis on years with larger tax payments while recognizing that years with low or negative payments do occur. Our calculation, as shown below, yields a $103.360 million reduction to rate base relative to SCE's proposal in 2015.

	Dollars (millions)	Adopted Lag Days	Dollar-Days
Federal	$ 456.893	85.98	39,285
Deferred	$ (72.595)	0.00	-
State	$ 97.512	56.34	5,494
Total	$ 481.810	92.94	44,778
	Dollars (millions)	Requested Lag Days	Dollar-Days
Federal	$ 456.893	7.16	3,273
Deferred	$ (72.595)	0.00	-
State	$ 97.512	38.75	3,778
Total	$ 481.810	14.64	7,052
Lag Day Difference		78.30	

[1135] SCE-26V2 at 61-62.
[1136] TURN OB at 302-307.
[1137] D.12-11-051 at 641-642.

Rate Base Difference	$ 103.360		

SCE accepts certain other TURN proposed adjustments, including an adjustment to labor lag days if LTIP is rejected, as it is in Section 10.3 above.[1138] These adjustments are reasonable.

23.5. Customer Deposits

Since SCE's 2003 GRC, we have used the amount of customer deposits as an offset to SCE's working cash, and therefore rate base. SCE seeks to end this policy and provides a lengthy discussion of its reasoning that customer deposits should not offset rate base. SCE's arguments are:

- Customer deposits are not defined as offsets to rate base in Standard Practice (SP) U-16.
- Customer deposits are different than rate base offsets in SP U-16 because they are debts that bear interest and are not the result of timing differences between utility revenues and expenses.
- Commission precedent is inconsistent and many Commission decisions have not required other utilities to offset rate base for customer deposits.
- Compensating SCE for interest paid on customer deposits is not as valuable as the earnings on equivalent rate base, over $10 million in 2012.
- Lower earnings, due to lower rate base, impacts various ratios considered by credit rating agencies and investors. In particular, SCE discusses the impact on Earnings Before Interest, Taxes, Depreciation, and Amortization (EBITDA) and EBITDA/interest. SCE notes that this has not caused a downgrade, but "will weaken SCE's credit quality relative to its California peers."
- The amount of customer deposits fluctuates due to factors outside of SCE's control such as CPUC credit policies. SCE notes that deposits declined 19% between 2009 and 2012.

[1138] SCE OB at 315-316, SCE-26V2 at 62-65.

- The rate base offset impacts SCE's ratemaking capital structure, by 0.5%. This impact is compounded by excluding nuclear fuel inventories.
- The rate base offset provides a rate of return to customers as a group greater than appropriate for the level of risk they assume.

Finally, SCE proposes to continue its practice of depositing up to 10% of customer deposits in Women, Minority, and Disabled Veteran Enterprise (WMDVE) banks or banks doing business in those communities. SCE explains that banking is a challenging area to use WMDVE suppliers, and that supporting these banks may in turn support lending to other community businesses that may be potential WMDVE suppliers of other services. If any earnings difference occurs because of this program, SCE splits the difference 50/50 between shareholders and ratepayers.[1139]

TURN argues that the policy should be continued. TURN's reasons are:

- Customer deposits are a permanent source of capital. The "only" difference from other permanent capital sources, aside from investors, is interest. TURN notes that interest rates have been low since 2009; at the time of TURN's testimony, the relevant rate was approximately 0.25%.
- Other states view deposits as a source of capital, either as a reduction to rate base or an element of the capital structure. In some states using the reduction to rate base approach, utilities have lower portions of equity.
- SCE rate case decisions have articulated reasons that SCE's customer deposits should offset rate base, SP U-16 notwithstanding.
- That the CPUC has set capital structure and cost for a decade, for SCE, knowing of this policy and presumably considers the combined outcome to be reasonable.

[1139] SCE-10V2R1 at 82-94.

- The impact of the additional debt on SCE's risk profile is small. Credit agencies have not made any downgrade of SCE as a result of this policy.
- There are material differences between SCE and PG&E, including PG&E's under-collection in certain balancing accounts.
- There need not be any connection between ratemaking treatment of nuclear fuel inventory and customer deposits. SCE's remaining fuel balance is small.

TURN recommends a reduction to rate base for 90% of customer deposits ($180.629 million at the end of 2013). Interest expense should be authorized on this 90%. TURN supports SCE's community bank program for the remaining 10%.[1140]

SCE claims that TURN "ignores key attributes" of deposits and "underplays" impacts on SCE. First, SCE states that it anticipates interest rates to rise, increasing the import of the difference between deposits and other rate base offsets. Second, SCE contends that deposits are debts, and therefore distinguishable from other offsets. Third, SCE labels TURN's comments no financial risk as "conjecture" and claims that "without looking at each utility and its particular circumstances . . . no valid insights" can be drawn. Fourth, SCE reiterates that deposits are debt, not equity. Fifth, SCE contends that differences between SCE and PG&E, in particular balancing account collections, are not relevant. Finally, SCE contends that its remaining nuclear fuel inventory is comparable to the amount of customer deposits.[1141]

In our analysis, we first consider SCE's point that drawing "valid insights" about the financial implications of this policy requires an analysis of that utility's specific circumstances. We agree. However, we note that the majority of SCEs testimony on this subject is very general. The only analysis SCE provides in its

[1140] TURN-5 at 132-139.
[1141] SCE-26V2 at 66-70.

direct showing that is specific to its circumstances are these points: 1) customer deposits declined 19% in recent years, 2) the impact to SCE's capital structure of the policy is 0.5% if the separate impact of nuclear fuel is excluded or 0.9% if it is included, 3) SCE estimates the effective rate of return to customers as 11.59%, and 4) SCE's lost earnings as a result of the $190 million offset in 2012 exceeded $10 million. None of these facts are in dispute here, and TURN's comments discuss some of these facts as much as SCE does. TURN's primary additional point that is specific to SCE's circumstances is to differentiate SCE and PG&E on the basis of their balancing account collections. SCE remarkably dismisses TURN's point as irrelevant, despite the clear emphasis on balancing account collections discussed in context of this issue in D.14-08-032. On balance, it appears that TURN's analysis of SCE-specific issues is as in-depth as SCE's.

SCE has not provided any clear reason, other than those addressed in previous decisions, to change our policy with respect to SCE here. Therefore, we decline to make a change and find the existing policy reasonable. SCE's rate base shall be offset in the amount of $180.269 million, and SCE may charge an offsetting interest expense based on the three-month commercial paper interest rate. We approve the continued 10% for the community banking program, and SCE may deposit up to $20.030 million in this manner.

However, we note that the issue of the proper rate making treatment of customer deposits may be appropriately addressed in a future cost of capital proceeding.

23.6. AFUDC

SCE presents its proposed rates for AFUDC.[1142] No party contests these rates. We find them reasonable.

[1142] SCE-10V2R1 at 15-17.

24. Results of Examination

ORA states that it conducts examinations in accordance with §§ 314, 314.5, and 309.5 of the Public Utilities Code. ORA describes certain recommendations as a result of its examination of SCE's records and controls.[1143] We address ORA's recommendations in Section 12 above.

25. Operational Excellence (OpX)

OpX is a framework SCE has created to pursue "Continuous Improvement" across the company, reduce costs, and improve efficiency. SCE states that OpX benefits are seen as reductions in O&M expenses, particularly in A&G accounts.[1144] SCE forecasts OpX savings of over $80 million in O&M and over $30 million in 2015 capital.[1145] The drivers for these savings are discussed in the specific subject sections above.

ORA proposes a number of increases to the forecast OpX savings that appear to be the result of a misunderstanding of SCE's use of the phrase "Add to fully staff." ORA claims that SCE did not provide any justification for these "additional" positions.[1146] However, SCE explains that the phrase refers to shifting employees into existing, vacant positions during the OpX reorganization process, not adding new employees.[1147] ORA does not cite any reason that these existing, vacant positions should not be filled. ORA's proposal is rejected. No other party disputes the level of OpX savings forecast by SCE. We find SCE's forecast of OpX savings reasonable.

SCE proposes that customers receive 100% of the benefits of 2013 and 2014 OpX savings in 2015 rates, as well as 100% of the 2015 benefits based on mature

[1143] ORA OB at 419-421.
[1144] SCE-1 at 7.
[1145] SCE-10 V2R1 at 99.
[1146] See ORA OB at 422-437.
[1147] See SCE OB at 325, SCE-28 at 3, and SCE-28 at App. A.

cost savings initiatives. SCE further proposes a 50-50 sharing of incremental savings estimated in 2015 for the course of the GRC cycle for business units such as IT and Customer Service where savings are less certain.[1148] SCE notes that similar sharing approaches have been adopted before.[1149]

ORA proposes that 100% of 2015 savings in Customer Service and IT go to ratepayers. ORA notes that OpX IT downsizing began in 2012 and argues that customers have been overpaying for these earlier reductions during the 2012-2014 time period as support for its recommendation.[1150] ORA calculates the additional savings to ratepayers as $19.944 million for IT and $4.992 million for Customer Service.[1151] SCE explains that these savings are subject to capitalization (37% for IT, 7% for customer service) and that in the case of IT, additional expense is required to realize the savings. After these adjustments, the incremental savings would be $3.796 million for IT and $4.643 million for customer service.[1152] Both parties make good points, and we adopt a compromise that 75% of the 2015 forecast savings should go ratepayers, as calculated with the adjustments for capitalization and additional expense. This resolution gives the majority of forecast savings to ratepayers, but recognizes that SCE is not certain to achieve the savings. Therefore we add $1.890 million and $2.321 million to the forecast savings for IT and customer service, respectively.

ORA proposes that 100% of "Financial Service Centralization" savings be allocated to nine business operating units, excluding SONGS, arguing that these savings were independent of SONGS.[1153] SCE responds that a portion of these savings were SONGS-specific, and should be removed from this GRC, consistent

[1148] SCE-10 V2R1 at 100, SCE-28 at 13, and SCE OB at 319.
[1149] SCE OB at 319, citing D.91-12-076 and D.06-05-016.
[1150] ORA OB at 431-432, citing RT 253.
[1151] ORA-19 AR at 26; ORA OB 431.
[1152] SCE-28 at 11-12.
[1153] ORA OB at 427-428.

with the Scoping Memo.[1154] We agree with SCE, noting that in Section 12.1.1, we approved SCE's reduced forecast for certain finance expenses, including the financial services centralization.

26. Joint Testimony Regarding Accessibility Issues

SCE and Center for Accessible Technology (CforAT) negotiated a joint proposal to address accessibility issues tied to SCE's role as a public utility and aid SCE's community of customers who have disabilities. The proposal increases the scope of activities to be undertaken and takes key steps to institutionalize such improvements. The parties forecast the average costs of this proposal as $1.5 million per year during this GRC cycle, incremental to the requests discussed elsewhere in this decision. Details of the program include:

- SCE would be required to provide an annual report to CforAT (and other parties on request) on SCE's annual spending each April. The report would identify SCE's spending on accessibility activities.
- SCE would hire or designate a full time Accessibility Coordinator. This person would have no other duties for at least a year.
- Annual consultation about planned spending for the following calendar year.
- Costs include costs of the coordinator, trainings, and various projects related to ensuring SCE's facilities and website are accessible.
- SCE will track spending via one or more specific internal orders.[1155]

No party challenged or expressed any concern with the joint proposal. While we support the goals of the joint proposal, we note that the specific cost forecasts are very vague. Due to the fact that the parties propose a new program that potentially includes costs across a wide variety of organizations within SCE,

[1154] SCE RB at 201-202.
[1155] SCE-12.

we are willing to accept this forecast, but only on a temporary basis. If SCE wishes to continue this program in the next GRC period, it must provide a considerably more specific forecast and justification. In its direct showing, SCE shall include: a description of the accomplishments of the program up to that point, analysis of specific forecast costs, and demonstration that such costs are complementary and not duplicative of other forecasts.

27. Settlements

27.1. Underserved and Hard-to-Reach Communities

On February 2, 2015 SCE and JMP filed and served a motion for adoption of a settlement agreement. No other party commented on the motion or settlement agreement. In the agreement, the parties agree to collaborate on a variety of issues related to underserved and hard-to-reach communities. Some specific commitments include:

1. Collaboration on outreach to minority and low-income customers about relevant Commission-authorized programs, including on improving effectiveness criteria and metrics
2. Collaboration on outreach to hard-to-reach communities on safety issues and rate impacts.
3. SCE will hire or designate a full-time Veterans Coordinator.
4. SCE will consider JMP nominations for SCE's Consumer Advisor Panel or Small Business Advisory Panel.
5. SCE will file testimony in its next GRC (or as directed by CPUC) on engagement with community-based organizations and SCE's efforts on employment diversity.
6. SCE will strive to improve its supplier diversity.

In their joint motion, SCE and JMP assert that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest. We agree that the settlement meets the requirements of Rule 12.1(d). In particular,

we note that improving safety-related communications to all communities is in the public interest. Therefore, we approve the settlement between SCE and JMP.

27.2. Streetlights

On February 2, 2015 SCE and Cal-SLA filed and served a motion for adoption of a settlement agreement. ORA and TURN contest the settlement. CASL also filed and served comments on the settlement. On March 9, 2015 SCE and Cal-SLA jointly replied to the comments of the other parties, and on April 7, 2015 filed and served an amendment to the joint reply comments.

In the settlement, SCE and Cal-SLA agree to work together to on issues related to AB 719 and converting streetlights to Light Emitting Diode (LED) bulbs. In particular, SCE agrees to work with Cal-SLA to develop an LED proposal in R.13-11-005, propose a financing mechanism to eliminate upfront capital costs to customers for LED conversion, explore the use of LEDs for new installation programs, and conduct relevant stakeholder meetings. The parties also agree to support SCE's forecasts for streetlight programs, discussed in Section 7.8 above.[1156]

ORA asks that the we reject "the part of the Settlement that would have the Commission adopt SCE's forecast for SCE's streetlight programs."[1157] SCE and Cal-SLA acknowledge that adopting the settlement does not require us to adopt any particular forecast for the streetlight programs.[1158] We agree.

TURN opposes the same provision of the settlement, alleging there was no material disagreement between the parties on the level of costs.[1159] As noted above, the provision does not require us to adopt any particular forecast for the streetlight programs.

[1156] SCE and Cal-SLA, February 5, 2015 motion, Appendix B.
[1157] ORA Comments on Settlement at 3.
[1158] SCE and Cal-SLA joint reply at 3.
[1159] TURN Comments on Settlement.

CASL makes a number of comments related to the sale of SCE-owned streetlights to public agencies.[1160] SCE and Cal-SLA claim that the issues raised by CASL are not relevant to the settlement or this proceeding more generally.[1161] We agree.

We find that the settlement is not directly relevant to this proceeding, and thus we neither approve nor reject the settlement. The settlement does not have any direct impact on the revenue requirement ultimately approved in this decision. SCE and Cal-SLA remain free to work with each other on LED and streetlight issues in the manner discussed in the settlement; indeed, we encourage such collaboration.

28. Other Issues

28.1. SCE and Logo

SCE disbursed $262,906 on clothing and other gear (excluding uniforms, hard hats, etc.) containing the SCE name and logo in 2012. Embedded in non-labor forecasts across numerous operational units, SCE has included a nominal amount of expense (approximately $156,073) and the remaining amount ($92,536) was allocated to capital. SCE claims this gear is used primarily to recognize high performance and improve morale.[1162]

TURN claims that these are promotional and image-building expenses that should not be charged to ratepayers. As a result, TURN proposes reducing O&M by $0.156 million and gross plant by $0.324 million (2015 weighted average).[1163]

SCE contends that TURN offers "no rationale" to oppose this "nominal gesture." SCE claims these expenses motivate employees to put in extra effort,

[1160] CASL Comments on Settlement.
[1161] SCE and Cal-SLA joint reply at 5.
[1162] SCE-28 at 27.
[1163] TURN-5 at 121-122.

and therefore benefit ratepayers. Further, SCE claims that the Commission has considered and rejected similar adjustments in the 2003 and 2006 General Rate Cases. SCE cites examples of California state agencies using similar recognition programs for employees.[1164]

In PG&E's most recent rate case, we adopted a similar proposal from TURN with respect to O&M expense for this type of program. In that case, there was no analogous capital recommendation.[1165]

We agree with SCE that this type of modest recognition program is a reasonable means to motivate employees to perform well. However, we find that SCE has not fully justified the particulars of its proposal, which we note is larger than that of PG&E. Further, SCE's testimony language suggests that some portion of these costs may be used for other purposes. We disagree with SCE that any of these costs should be capitalized as the items involved do not remain utility property. Accordingly, we adopt TURN's proposal in part and reduce gross plant by $0.324 million (2015 weighted average). We do not reduce SCE's O&M forecasts on this basis. The remaining O&M funding is reasonable to allow SCE to use this recognition approach to motivate employees to benefit ratepayer interests.

28.2. Greenhouse Gas Revenues

TURN proposes a reduction to SCE's revenue requirement on the basis of the gross-up for Franchise Fees and Uncollectibles as well as a change in lag days for cash working capital.[1166] SCE shows that its balancing account handles this gross-up consistent with Commission decisions and that 2015 GHG revenue

[1164] SCE-28 at 27-29.
[1165] D.14-08-032 at 581.
[1166] TURN-5 at 114-120.

returns are in the scope of A.14-06-010.[1167] SCE modified its revenue lag days calculation based on TURN's GHG recommendation in rebuttal.[1168]

Based on SCE's explanation of the Franchise Fees and Uncollectibles, as treated in the balancing account, we agree with SCE that TURN's recommendation is moot.

29. Comments on 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 October 8, 2015 and reply comments were filed on October 13, 2015 by SCE, ORA, TURN, SDG&E, and CUE.

29.1. ORA's Cited "Unresolved Issues"

ORA suggests that the Proposed Decision does not resolve all issues in the case. We disagree.

First, ORA suggests that there are errors in the RO model and that the model constitutes a "black box" in violation of §1821. In response, SCE observes that ORA itself has used the model extensively in this proceeding. ORA has proposed no viable alternative, nor cited any specific errors that are not addressed in this decision. Accordingly, we reject ORA's argument.

Second, ORA suggests that the Commission has not addressed its proposal for an Order to Show Cause related to SCE's showing on intrusive and visual pole inspections. We have reviewed the record and approve SCE's forecast for intrusive inspections. We do not find that any shortcomings in SCE's showing on the topic rise to the level of a violation.

[1167] SCE-26v1 at 26-27.
[1168] SCE-26V2 at 62-63.

29.2. Changes in Response to Comments

In response to comments, we have made a number of changes relative to the Proposed Decision. Those changes include the following subjects:

- Nuclear Generation in Section 6.3
- Hydro O&M in Section 6.5.1
- Ratemaking for PLP in Section 7.7.4
- Streetlights Capital in Section 7.8.2.2.2
- Manual Meter Reading O&M in Section 8.1.1
- Customer Service OOR in Section 8.3
- Personal Computers Capital in Section 9.2.4
- Executive Incentive Compensation in Section 10.1
- Short Term Incentive Compensation in Section 10.2
- SONGS Marine Mitigation O&M in Section 11.2
- Law Department O&M in Section 12.4.1

In addition to these subjects, we have also corrected errors and/or clarified our discussion of certain issues.

We have changed some of the implementation timing requirements (e.g. due dates for advice letters) in recognition of the timing of this decision.

Finally, we have also made certain changes in the RO Model. SCE filed a motion to update the RO Model after the Proposed Decision was published; the motion was granted by the ALJ and this decision uses the updated model. The treatment of the tax-related ratebase offset adopted in Section 22.2 above is also implemented differently in the version of the RO model supporting this decision than the version supporting the Proposed Decision.

30. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Kevin Dudney is the assigned ALJ in this proceeding.

Findings of Fact

Section 6.1

1. SCE bases its forecast of O&M and capital expenditures for power procurement on expected numbers of new generators.

2. SCE's forecast of O&M and capital expenditures for power procurement are reasonable.

Section 6.4

3. SCE's unopposed forecast of $0.308 million in O&M for Mohave Generating Station is reasonable.

4. It is reasonable to eliminate the Mohave Balancing Account.

Section 6.5

5. There is no clear trend in recorded data for non-labor hydro O&M and a long term average is appropriate to forecast these costs.

6. 2013 recorded data is informative for FERC Account 536 and are appropriate to include in the forecast.

7. Labor costs in FERC Accounts 539 and 545 have been steady and LRY is an appropriate forecast basis for these costs.

8. A total hydro O&M forecast of $52.849 million is reasonable.

9. SCE's uncontested revised rebuttal forecast for hydro capital is reasonable. The forecast is ($ millions, nominal):

2014		2015

71.149		90.231

Section 6.6.1

10. There is no clear trend in recorded Base O&M costs for Mountainview.

11. SCE's historical averaging approach to develop its Mountainview Base Forecast is reasonable.

12. There is no clear trend in FFH for Mountainview.

13. SCE's historical averaging approach for CSA Annual Payments for Mountainview is reasonable.

14. ORA's proposal to use 2009-2013 data to forecast CSA Major Outage fees is reasonable.

15. A total O&M forecast of $48.338 million for Mountainview, in FERC Accounts 549 and 554, is reasonable.

16. For Mountainview capital expenditures, the unopposed SCE and ORA recommended forecast of $1.327 million and $1.131 million for 2014 and 2015 respectively is reasonable.

Section 6.6.2

17. There is low recorded variation in Peakers O&M in FERC Accounts 549 (labor and non-labor) and 554 (labor).

18. SCE's LRY base forecast for Peakers O&M in FERC Accounts 549 (labor and non-labor) and 554 (labor) is reasonable.

19. There is significant recorded variation in Peakers maintenance in FERC account 554 (non-labor).

20. SCE's four-year average base forecast for Peakers maintenance in FERC account 554 (non-labor) is reasonable.

21. Because the McGrath peaker only operated for part of 2012, it is reasonable to use 2013 recorded McGrath costs.

22. A total Peakers O&M forecast of $10.155 million is reasonable.

23. SCE's capital expenditures request of $2.954 million in 2014 and $3.043 million in 2015 for the Peakers is reasonable.

Section 6.7

24. A total forecast of $3.503 million for SPVP O&M is reasonable. Added facilities costs are not subject to escalation.

25. SCE's has not established that its contract with or termination payment to SunPower was prudent.

26. SCE's SPVP capital expenditure request of $0.425 million for 2014 and $1.035 million for 2015 is uncontested, and is reasonable.

27. SPVPBA can be eliminated.

28. TURN's forecast of $4.360 million in O&M for Catalina is unopposed, consistent with our guidelines, and is reasonable.

29. SCE has not demonstrated that its capital expenditure request for Catalina is reasonable.

30. Some delays in the PB Project were beyond SCE's control, but others were not.

31. It is reasonable to allow SCE to recover Catalina AFUDC and capitalized property taxes through the end of 2013, in addition to $5.1 million in capital expenditures recorded by that time.

32. Two thirds of an FTE is appropriate for the fuel cell program.

33. Confidential availability data suggests that a reduction of $0.043 million in non-labor for the fuel cell program is reasonable.

34. A total O&M forecast of $0.589 million is reasonable for the fuel cell program.

35. The FCPMA can be eliminated.

Section 7.1 - (T&D – Policy)

36. The relationship between safety, reliability, and resiliency is complex.

37. Encouraging SCE to spend its authorized capital forecast on key programs to meet our goals of safety, reliability, and resiliency and retain employees in classifications responsible for this work is reasonable.

38. It is reasonable to adopt some type of RIIM-mechanism.

39. SCE's proposed core RIIM capital categories WCR, Underground Cable Life, CIC Replacement, Underground Switch, Underground Structure Replacement, Circuit Breaker Replacements, and Substation Transformer Replacement} are unopposed and are reasonable.

40. SCE's proposed High Priority RIIM categories (customer growth, storms, and claims) are unopposed and are reasonable.

41. SCE's proposed RIIM staffing target proposal (2,225 employees in the categories identified at SCE-3V1 at 27) is reasonable.

42. It is suboptimal to divert funding from core categories of the new SRIIM to the High Priority categories, potentially delaying important work.

43. It is unreasonable to ask shareholders to fund core utility work.

44. It is reasonable to adopt the TURN/CUE proposal for the mechanics of the SRIIM capital spending mechanism with the following modifications. Overspending in the High Priority categories can offset underspending in the core SRIIM categories if two conditions are true: the overspending in High

Priority categories exceeds ten percent of the adopted forecast for those categories and SCE's actual rate of return on rate base for the period does not exceed the authorized rate of return. The first ten percent of overspending on High Priority categories cannot be used to offset underspending in the core SRIIM categories under any circumstance.

Section 7.2 - (T&D – Engineering and Grid Technology)

45. SCE has not fully quantified expected benefits of CRAS, but CRAS may support efficient operation of variable renewable generation resources.

46. It is reasonable to approve SCE's 2013 capital expenditure request for CRAS and to allow SCE to reapply for capital expenditures in later years.

47. SCE requests $51.223 million in O&M for Engineering and Grid Technology. ORA agrees with this forecast.

48. In order to account for capital expenditure disallowances, a portion of SCE's O&M forecast is disallowed. $51.058 million of SCE's O&M request for Engineering and Grid Technology is reasonable.

49. Portions of the Westminster Lab Upgrades and EDEF have not been shown to be cost effective and/or focused on SCE specific issues. These capital expenditures are unreasonable.

50. SCE has shown the remaining portions of its Engineering and Grid Technology capital expenditures request to be reasonable.

51. It is reasonable to approve Engineering and Grid Technology capital expenditures as follows ($000s): $40,217 in 2014 and $31,681 in 2015.

Section 7.3.1 - (Transmission Planning Projects)

52. SCE's forecasts for uncontested transmission planning projects are reasonable.

53. The fourth A-bank transformer at Victor Substation was needed for reliability during construction.

54. SCE's forecast for the Victor Substation is reasonable.

55. SCE's forecasts for other transmission planning projects are reasonable.

Section 7.3.2 - (Load Growth Planning Projects)

56. SCE's forecast of A-bank plan expenses for 2014-2015 is reasonable.

57. SCE's forecast of subtransmission line plan expenses for 2014-2015 is reasonable.

58. SCE's DSP forecast for 2014-2015 reasonable.

Section 7.3.3 - (System Improvement/Reinforcement Program)

59. Some increase in the rate of circuit breaker replacement is warranted.

60. Funding for 60 circuit breaker replacements per year, or $9.887 million is reasonable.

61. SCE's forecast for the DSP circuit work category is reasonable.

62. SCE's forecasts for Capacitor and Circuit Automation Programs are reasonable.

63. SCE's forecasts for Distribution Plant Betterment, Distribution VAR Plan, and Substation Load Information Monitoring are reasonable.

Section 7.3.4 to 7.3.5

64. SCE's 2014-2015 forecast for Generator Interconnection Program is reasonable.

65. SCE's 2014-2015 forecast for Added Facilities Projects is reasonable.

Section 7.4.1 (Underground Cable Programs)

66. SCE has developed new approaches for testing that initially appear successful and cost-effective, at least for CIC.

67. Employing testing procedures to reduce the amount of cable to be replaced in order to achieve equivalent reliability benefits may significantly reduce costs (both financial and otherwise) to customers.

68. SCE can and should have done more to accelerate its use of testing.

69. The benefits to customers of reducing the amount of good cable replaced through testing outweigh the benefits to customers of accelerated replacement of more total cable, without testing.

70. It is reasonable for the WCR program to replace approximately 250 miles of cable in 2014 and 300 miles in 2015.

71. It is reasonable for the CIC program to replace approximately 100 miles of cable in 2014 and 175 miles in 2015.

72. $0.300 million (2012$) per mile is a reasonable unit cost forecast for trenchless CIC replacement.

73. TURN's estimate of $0.610 million (2012$) per mile is based on historical data and is a reasonable unit cost forecast for trenched CIC replacement.

74. $0.403 million (2012$) per mile is a reasonable unit cost forecast for CIC replacement.

75. SCE's forecast costs for TBCLE is reasonable.

76. The following total forecast for underground cable programs is reasonable:

		2014		2015	
		Requested	Adopted	Requested	Adopted
WCR		85.086	85.086	112.961	104.272
	Miles	250	250	325	300
	$/mile	0.340	0.340	0.348	0.348
CIC		65.451	42.228	93.577	75.452
	Miles	125	100	175	175
	$/mile	0.524	0.422	0.535	0.431
TBCLE		13.167	13.167	26.892	26.892
Total		163.704	140.481	233.430	206.616

($millions)				

Section 7.4.2

77. Historical replacement rates are an important predictor of future replacements.

78. Increasing the rate of A-bank replacements above the historical average is an appropriate step to reduce safety and reliability risks.

79. It is reasonable to adopt SCE's recorded A-bank replacements for 2013 and 3.5 CPUC-jurisdictional replacements in each of 2014 and 2015, for a total of nine A-bank replacements.

80. SCE's uncontested unit costs for A-bank replacements are reasonable.

Section 7.4.3

81. It is reasonable to allow SCE funding to reduce in-service circuit breaker failures.

82. A small increase in the rate of circuit breaker replacements to 180 per year above the adopted rate of 175 in the last GRC is reasonable.

83. SCE's uncontested unit costs for circuit breaker replacements are reasonable.

Section 7.4.4

84. ORA's uncontested forecast for B-bank transformer replacements is reasonable.

85. SCE's uncontested forecasts for 4kV Circuit replacement programs are reasonable.

86. SCE's uncontested forecasts for other infrastructure replacement programs are reasonable.

Section 7.5.1

87. The methods adopted for calculating customer driven expenses and expenditures should be applied to the forecast of new meters and other items adopted in this decision, instead of any party's forecast of those values.

88. The actual number of meters installed in the post-test years is forecast to be considerably higher than in 2015.

89. SCE's proposal to levelize the forecast of Account 586.140, Meter Installation and Replacements is reasonable.

90. The attrition mechanism is consistent with rent inflation in the Distribution Line Rents portion of Account 588.140 and this forecast does not need to be levelized.

91. SCE's forecasts for other elements of 588.140 and all of account 588.271 are uncontested and are reasonable.

92. The total O&M forecast for Customer-Driven Programs and Distribution Construction of $15.573 million is reasonable.

Section 7.5.2

93. All else equal, a weighted average is likely to be less influenced by outliers and is preferable to an arithmetic average.

94. TURN's recommended five-year weighted average approach to calculate unit costs of customer meter connections is reasonable.

95. TURN's regression models for calculating unit counts of meter connections are reasonable.

96. ORA's uncontested forecast for Rule 20A undergrounding expenditures is reasonable.

97. TURN's uncontested unit cost and approach for calculating unit counts for Rule 20B&C undergrounding expenditures is reasonable.

98. The following total capital forecast for disputed items of Customer-Driven Programs and Distribution Construction (including transformers and prefabrication) is reasonable: $384.259 million in 2014 and $497.795 million in 2015 (nominal$).

Section 7.6.1 - Underground Structures

99. Changes specifically identified by SCE are inadequate to explain the increase in failure rate of underground structures.

100. Unit repair and replacement costs for underground structures are likely to decline with economies of scale.

101. SCE has an existing queue of underground structures that have failed an inspection.

102. Structures that have failed an inspection pose a hazard.

103. It is reasonable to approve O&M as follows for underground structures (millions of 2012$):

	Requested		Approved	
Account	583.120	593.120	583.120	593.120
Labor	4.523	1.669	4.523	1.335
Non-Labor	1.678	14.964	1.678	11.971
Total	6.201	16.633	6.201	13.306

104. It is reasonable to approve capital expenditures for underground structure replacement as follows (millions of nominal $):

	2014	2015
Requested	$ 67.500	$ 67.500
Approved	$ 54.000	$ 54.000

Section 7.6.2

105. SCE's use of LRY to forecast distribution maintenance O&M is appropriate.

106. It is reasonable to approve SCE's uncontested distribution maintenance O&M forecast as follows:

Account	593.120	594.120	Total
millions of 2012$	50.879	27.454	78.333

107. It is reasonable to approve SCE's uncontested distribution maintenance capital forecast as follows:

2014	2015
250.396	255.713

Section 7.6.3 - DIMP O&M

108. SCE's decision to require inspectors performing an ODI to access each pole is appropriate.

109. SCE's forecast of additional ODI costs to reach difficult-to-access poles is credible.

110. SCE's ten-year, grid-based intrusive inspection cycle as a reasonable approach to reduce risk and reduce unit costs.

111. In order for SCE to complete the transition to grid-based inspections, it is necessary to intrusively inspect more poles than would be possible under ORA's forecast.

112. SCE's uncontested forecast of JPO expenses based on LRY is reasonable.

113. SCE may be under-collecting joint pole credits.

114. Increases in pole inspections are likely to increase the amount of joint pole penalty credits.

115. A forecast of $4 million for joint pole credits is reasonable.

116. A review of pole credits in the next GRC is worthwhile.

117. SCE's overhead conductor program mitigates conductor failure risk.

118. SCE presents credible cost assumptions for the overhead conductor program.

119. SCE's cost forecast for the overhead conductor program is reasonable.

120. SCE's forecasts for the uncontested elements of Accounts 593.120 and 594.120 are reasonable.

121. SCE's request to close the Bark Beetle CEMA is reasonable.

Section 7.6.4 - Poles – Capital Expenditures

122. Pole replacement unit costs increased significantly during 2009 to 2012.

123. A 3% reduction to SCE's unit costs for transmission and distribution pole replacement costs is reasonable.

124. SCE's forecast of cost of removal is based on recorded, actual costs incurred, net of joint pole credits, and does not double count cost of removal.

125. SCE's forecast of deteriorated pole replacements is based on past and predicted inspection failures.

126. SCE's forecast of deteriorated pole replacements is reasonable.

127. Pole inspection failure rates are much lower beginning in 2009, after poles were being inspected for the second time under the GO 165 inspection program.

128. SCE's data clearly shows lower failure rates for all poles (both aged and non-aged) that are much lower in 2009 and beyond than in 2008 and earlier.

129. Infrastructure replacement may be appropriate in circumstances of limited effective testing options; SCE has not demonstrated this circumstance in the case of the aged pole replacements.

130. 9,000 aged pole replacements in 2014 provides a reasonable ramp up in 2014 toward the approved level of pole replacements for PLP in 2015, making 2014 approximately a mid-point between 2013 and 2015 levels.

131. The following forecast of aged pole replacements is reasonable:

Aged Pole Replacements		2014	2015
Poles Replaced	Adopted	9,000	0
	Requested	14,500	1,898
Nominal$, millions	Adopted	114.32	0
	Requested	184.189	24.622

132. SCE's uncontested forecast of $100 per wood pole disposal is reasonable.

Section 7.6.5 - Other Capital

133. SCE's Distribution Inspection and Maintenance capital expenditure forecasts that are not specifically addressed are uncontested and are reasonable.

Section 7.7.2.1 - PLP Assessments and Planning

134. Economy of scale may decrease unit costs of pole assessments.

135. ORA's proposed $106 per pole based on recorded data is a reasonable forecast of pole assessments.

136. The public interest in quickly developing a more comprehensive understanding of the extent of overloaded poles outweighs the potential cost deferral advantage of slowing the pace of assessments.

137. SCE's proposed ten-year assessment schedule is reasonable.

138. SCE's uncontested forecast of planning and analysis is reasonable.

139. The following total forecast for PLP assessments is reasonable:

	2014	2015
Assessments per year	205,754	205,754
Unit Cost (2012$)	$ 106	$ 106
Subtotal (millions of 2012$)	$ 21.810	$ 21.810
Planning & Analysis Cost (millions of 2012$)	$ 0.301	$ 1.812
Total Assessment Cost (millions of 2012$)	$ 22.111	$ 23.622
89% to 583.125 – Distribution	$ 19.678	$ 21.023
11% to 566.125 - Transmission	$ 2.433	$ 2.599

Section 7.7.2.2 - PLP Repair

140. SCE's uncontested unit costs for repairs are reasonable.

141. SCE's total forecast of repair costs is reasonable.

Section 7.7.2.3 - PLP Related Expense

142. The relation between the replacement forecast and related expense is uncontested and is reasonable.

Section 7.7.2.4 - Joint Pole Organization

143. The relation between the replacement forecast and JPO expense is uncontested and is reasonable.

Section 7.7.3 - PLP Capital

144. Nearly 19%, of poles reviewed in SCE's PLP study are overloaded, and specifically failed the bending analysis. The study suggests similar failure rates in SCE's total population of poles.

145. An additional 3% of poles in the study are overloaded and could be repaired through addition or repair of guy wires. The study suggests a similar rate in the total pole population.

146. Overloaded poles present a significant safety hazard and reliability risk.

147. Approximately 70% of poles are joint use, supporting attachments of either renters, joint owners, or both.

148. Attachments contribute to overloading.

149. Credits from joint users are less than 10% of SCE's pole replacement forecast.

150. Options besides replacing overloaded poles should be considered.

151. PLP assessments should provide factual information about the extent to which attachments contribute to any valid safety or reliability concerns and potentially non-compliance with GO 95 standards.

152. Cost sharing in proportion to the contribution to pole overloading is not unduly discriminatory or anticompetitive.

153. For purposes of 2014 and 2015 capital expenditures, SCE's forecast of $844 (2012$) in credits per pole replaced is reasonable.

154. SCE may be able to remediate additional overloaded poles beyond those that are replaced at SCE ratepayer expense, either by removing attachments, strengthening existing poles, or achieving greater cost share contributions from joint pole users.

155. To the extent that poles can be remediated without replacement, fewer total poles may need to be replaced over the entire span of PLP to achieve a target level of safety and reliability improvements.

156. Overlap between PLP and other programs may reduce the number of poles ultimately replaced by PLP.

157. A forecast of 20% remediation without SCE ratepayer funded replacement is reasonable in light of the balancing account treatment adopted here and the considerable uncertainty surrounding the total number of poles replaced.

158. An estimate of 12% overlap between PLP and other pole replacements strikes a reasonable middle ground between the likely limited overlap in the early years and the higher potential overlap in later years.

159. A forecast of 3,000 PLP pole replacements in 2014 and 18,213 in 2015 is reasonable.

160. The following capital expenditures forecast is reasonable for PLP pole replacements:

Millions of Nominal$	2014	2015
Distribution	$32.899	$203.963
Transmission	$6.585	$41.043
Total	$39.485	$245.006

161. The relationships between other expenditures related to PLP and the number of pole replacements are undisputed, and SCE's proposals are reasonable.

162. The following ratios should be used to calculate forecasts of other capital expenditures related to PLP.

Ratios Based on Pole Replacements	
2014	2015
1	0.6778103

163. The total adopted pole replacement capital forecast summarized below is reasonable (millions of nominal$).

	SCE		Adopted	
	2014	2015	2014	2015
Pole Replacements - Distribution	$33.916	$288.636	$32.899	$203.963
Pole Replacements - Transmission	$.789	$58.080	$6.585	$41.043
Malibu adjustment		$(5.130)	$ -	$(5.130)
Distribution	$1.371	$11.668	$1.371	$8.500

Transformers				
Prefabrication	$0.931	$7.926	$0.931	$5.774
Joint Pole - Distribution	$(2.360)	$(20.083)	$(2.360)	$(14.631)
Joint Pole - Transmission	$(0.289)	$(2.476)	$(0.289)	$(1.804)
Wood Pole Disposal	$0.314	$2.674	$0.314	$1.948
Total	$40.672	$341.295	$39.452	$239.664

Section 7.7.4 - PLP Ratemaking

164. SCE's uncontested PLPBA proposal, as revised to include deteriorated poles, is reasonable.

165. A 15% cap on expenditures over forecast in the PLPBA is a reasonable protection for ratepayers during 2016 and 2017.

Section 7.8.1

166. GCC staffing must increase to accommodate increases in work due to the growing electric grid.

167. SCE's forecast for Account 561.170 is reasonable.

168. SCE's five-year average forecast method for storm expenses is reasonable given the inherent variability of storm expenses.

169. SCE's storm expenses forecast is reasonable.

170. The amount of overtime identified by ORA is less than half the cost of 18 additional troublemen.

171. Troublemen overtime can only be partially replaced by normal hours.

172. SCE's forecast for Account 583.170 is reasonable.

173. SCE's uncontested forecast for Account 585.170 is reasonable.

174. SCE's O&M forecasts for uncontested Grid Operations accounts are reasonable.

175. A total Grid Operations O&M forecast of $111.801 million (2012$) is reasonable.

Section 7.8.2

176. SCE's five-year average forecast method for storm expenditures is reasonable given the inherent variability of storm expenses.

177. SCE's storm expenditures forecast is reasonable.

178. Using recently recorded data is valuable to calculate unit costs for steel pole replacements due to the inconsistency in how the numbers have been developed in recent GRCs.

179. A steel pole replacement unit cost of $6,000 (2012$) is in the range of values presented by the parties and is a reasonable estimate.

180. The evidence suggests that low percentages of inland poles suffer significant corrosion.

181. The data provided from SCE's recent postmortem analysis suggest that poles within ten miles of the ocean are likely corroding.

182. An annual rate of 3,900 steel pole replacements is reasonable.

183. SCE's rebuttal proposal for luminaire unit costs and replacement counts is reasonable.

184. SCE's uncontested forecast for breakdown maintenance spending is reasonable.

185. SCE's uncontested forecast for operational facilities maintenance is reasonable.

186. The following forecast of Grid Operations Capital is reasonable.

(millions of nominal$)		2014	2015
Storm		$ 47.084	$ 48.110
	Transmission	$ 4.562	$ 4.683
	Substation	$ 0.316	$ 0.325

	Distribution	$ 42.206	$ 43.102
Streetlights		$ 38.872	$ 36.564
	Pole Replacement	$ 24.505	$ 25.025
	Luminaire Replacement	$ 12.273	$ 9.400
	Breakdown Maintenance	$ 2.094	$ 2.139
Operational Facilities Maintenance		$ 5.600	$ 5.749
Total		$ 91.556	$ 90.423

Section 7.9.1

187. SCE's forecast of line miles based on specific construction projects is superior to a forecast based on historical averages.

188. SCE's forecast of Overhead Inspections and Patrols is reasonable.

189. SCE's forecast of transmission line rents is reasonable.

190. SCE's five-year average unit costs for insulator washing and road and right of way maintenance are undisputed.

191. SCE's forecasts for insulator washing and road and right of way maintenance are reasonable.

192. Possible further permitting delays suggest a decrease to SCE's forecast of Big Creek vegetation management.

193. SCE has permission to start work from private landowners.

194. The following total forecast for transmission vegetation management is reasonable (2012$, millions):

Labor	$ 0.066
Non-Labor	$ 5.358
Total	$ 5.424

195. SCE's forecast of overhead and underground maintenance is uncontested and is reasonable.

196. SCE's forecast of transmission line rating remediation is reasonable.

197. SCE's forecast of substation circuit breaker maintenance, based on specific projects, is reasonable.

198. SCE's uncontested distribution relay inspection forecast is reasonable.

199. It is reasonable to base a forecast of transmission relay inspections on 1,178 relay inspections per year, the rate needed to actually levelize inspections over the six-year period identified by SCE.

200. The following forecast for transmission relay inspections (Account 568.150) is reasonable (millions of 2012$).

Total	$ 3.463
Labor	$ 2.874
Non-Labor	$ 0.589

201. A total transmission and substation maintenance O&M forecast of $84.739 million (2012$) is reasonable.

Section 7.9.2

202. In the case of unplanned work, there is no clear inverse relationship or anti-correlation between amounts spent in one year and needed in later years.

203. SCE's forecast of variable reactive work appropriately uses a five-year average.

204. SCE's forecast of predictable planned work appropriately uses 2012 recorded.

205. SCE's forecast for transmission capital maintenance work is reasonable.

206. SCE's five-year average forecasts of transmission and substation claims are reasonable.

207. SCE's forecast of line rating remediation is reasonable.

208. SCE provided a reasonable, project-based forecast of transmission relocation expenditures.

209. For long lasting transmission tools and work equipment, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the immediately following years. Preliminary 2014 recorded information cited by ORA is consistent with that expectation.

210. ORA's 2014-2015 forecast of transmission tools and work equipment is reasonable.

211. SCE's forecast of substation capital maintenance is reasonable.

212. SCE's forecast of online transformer monitoring is reasonable.

213. For the substation protection and control equipment being replaced according to a multi-year plan, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the following years.

214. ORA's 2014-2015 forecast for substation protection and control replacements is reasonable.

215. For long lasting substation tools and work equipment, it is reasonable to expect that increased spending in one year would lead to a decreased need to replace equipment in the immediately following years. Preliminary 2014 recorded information cited by ORA is consistent with that expectation.

216. ORA's 2014-2015 forecast of substation tools and work equipment is reasonable.

217. SCE's uncontested forecasts for transmission and substation spare parts are reasonable.

218. A total transmission and substation maintenance capital forecast of $121.636 million (nominal$) in 2014 and $131.865 million in 2015 is reasonable.

Section 7.10 (T&D – Safety, Training, and Environmental Programs)

219. SCE's approach to developing its forecast by considering specific training needs and number of relevant employees is preferable to relying only on 2012 recorded.

220. Training costs are directly related to the number of employees, particularly new employees.

221. Since our total adopted labor forecast is lower than SCE's it is reasonable to adopt a 10% lower training forecast.

222. SCE's modest employee recognition programs promote safety.

223. SCE's employee recognition forecasts are reasonable.

224. SCE's uncontested forecasts are reasonable.

225. A total forecast of $65.912 million (2012$) for T&D Safety, Training and Environmental Programs is reasonable.

Section 7.11 - T&D – Other Costs and Other Operating Revenue

226. Productivity improvements alone may not be adequate to address the forecast growth in number of contracts.

227. SCE is likely able to make further productivity improvements in Grid Contract Management.

228. Considering potential productivity improvements, $0.300 million, approximately enough for three additional employees, is a reasonable increase for Grid Contract Management.

229. A total forecast of $2.226 million is reasonable for Grid Contract Management.

230. A forecast of $2.625 for Meter Credits in Account 586.281 is reasonable.

231. TURN's proposed forecast of $9.793 million for write-offs in Account 588.281 is reasonable.

232. A 5YA ($10.148 million) for underground locating services is reasonable given the uncertainty in both price and volume moving forward.

233. SCE's approach to forecasting capital-related expense based on the historical relationship and the adopted capital forecast is reasonable.

234. A total reduction of 10% to account for reductions in the adopted capital expenditures forecast for T&D is reasonable.

235. The following total forecast for capital-related expense is reasonable (millions of 2012$).

Account	Description	SCE	Adopted
560.281	Transmission/Substation Capital-Related Expense	$ 8.778	$ 7.900
594.281	Distribution Capital-Related Expense	$ 17.159	$ 15.443

236. 2012 may represent unsustainably low levels of maintenance.

237. SCE's forecasts of facilities O&M based on 2011 are reasonable.

238. SCE's uncontested forecasts are reasonable.

239. A total forecast for operational support and other costs of $64.505 million (2012$) is reasonable.

240. ORA's uncontested forecasts of SCE-financed added/interconnection facilities are reasonable.

241. SCE's rebuttal forecast of customer-financed added/interconnection facilities is reasonable.

242. A total forecast of OOR of $128.369 million (2012$) is reasonable.

Section 8.1 - Customer Service O&M

243. There are important changes occurring at SOC that are not captured by historical data.

244. SCE's forecast of automatic meter reads and SOC costs is reasonable.

245. 2013 costs per manual meter read are most representative given the recent changes in the number and distribution of meters.

246. TURN's forecast manual meter reading cost is reasonable.

247. A total forecast for O&M in Account 902 of $16.771 million (2012$) is reasonable.

248. It is reasonable to deny SCE's request of $173,000 for the Service Guarantee Program, consistent with past precedent that ratepayers are not responsible for reimbursing inconvenienced customers.

249. SCE's Medical Baseline Program forecast was based on historic growth and the historic ratio of enrolment volume to total program participation.

250. SCE's request for incremental funding of $250,000 for the Medical Baseline program is reasonable.

251. Call center employees face increasingly complex tasks, warranting both increased supervision and increased wages; these specific wage increases are tied to a change in job skills required, not general inflation.

252. SCE's revised forecast of $47.435 million for Account 903.800 is reasonable.

253. A historical average of uncollectible expense is appropriate to avoid undue influence of variable economic factors.

254. SCE's forecast uncollectible factor of 0.238% is reasonable.

255. SCE's 2013 recorded costs for PMO are well below SCE's forecast, despite including a significant portion of the increase in functions described for the test year.

256. ORA's proposed PMO forecast is a significant increase over 2012 recorded, and allows SCE some funding to implement the additional functions it proposes.

257. ORA's proposed averaging approach for PMO is appropriate given the recorded fluctuations in this account.

258. ORA's proposed $6.343 million PMO forecast is reasonable.

259. O&M charged to Account 586.400 is based on the total meter population, more than the number of new meters.

260. New functions in ESC create incremental costs.

261. SCE's forecast for Account 586.400 is reasonable.

262. With the implementation of ESC and the accuracy of the data being analyzed and the ability to detect patterns of theft which triggers follow-up and investigations that previously would not have happened, new Customer Installation and Energy Theft expenses will arise.

263. SCE's forecast for Account 587 of $7.946 million ($6.947 million Labor and $0.999 million Non-Labor) is reasonable.

264. SCE's forecast for Account 908.600 is uncontested and is reasonable.

Section 8.2 - Customer Service Capital

265. SCE's revised meter unit cost forecast is uncontested and is reasonable.

266. There is no correlation between growth meters and replacement meters.

267. SCE's forecast of residential replacement meters is reasonable.

268. SCE's data shows a clear downward trend for volumes of non-residential meter replacements, with overall changes from 2008 to 2013 from negative 77% to negative 83%.

269. ORA's proposed volumes of non-residential meter replacements, based on 2013 recorded, is reasonable.

270. ORA's proposed $1,400 RTEM meter unit cost is reasonable.

271. SCE's updated forecast of legacy/opt-out meters based on D.14-12-078 is reasonable.

272. ORA's forecasts of PCAN meters and delayed ESC meter installations are reasonable.

273. A total MSO capital forecast of $13.888 million in 2014 and $16.392 million in 2015 is reasonable.

274. SCE has shown that its capital request for BCD will be used for reasonable improvements to energy education centers and to assist customers seeking to improve energy consumption management.

275. SCE's BCD capital forecast is reasonable.

Section 8.3 - Customer Service – OOR

276. SCE's charges and fees other than those related to ESC Opt-Out are uncontested and are reasonable.

277. A total Customer Service OOR forecast of $25.569 million is reasonable.

Section 9.1 - IT – O&M

278. Since recorded values for ITS are neither stable nor do they indicate a trend, the four-year averaging methodology proposed by ORA is the most appropriate for determining the baseline forecast.

279. Many of the costs cited by SCE as reasons for an increase in ITS are captured in historical cost data.

280. To account for new licenses and some escalation in the cost of existing licenses, it is reasonable to allow $4.170 million of the itemized increase to be added to the non-labor baseline.

281. SCE's OpX reductions for ITS consider headcount reductions.

282. The following forecast of ITS O&M for ITS is reasonable: $4.180 million for Labor and $66.501 million for Non-Labor, and a total of $106.680 million (2012$).

283. SCE hired 78% of its C&C non-labor positions in 2013 and hired at least two more contractors in 2014 out of a forecast four.

284. Addressing C&C issues is important.

285. Since SCE has demonstrated the critical nature of cybersecurity and compliance and that costs are growing, in this instance, we find that an increase of 22% (double the labor rate) over the 2014 non-labor forecast to $9.855 million, is appropriate.

286. C&C labor expenses have risen gradually, while there has been a decrease in non-labor expenses from 2010 to 2012.

287. SCE's increase in the labor forecast from 2014 to 2015 is in line with year-to-year increases starting in 2011.

288. SCE's labor forecast of $7.529 million for C&C is reasonable.

289. CS&P functions are either complimentary or different in scope, despite having similar descriptions.

290. A small amount of SONGS-related costs were not removed from the historical costs as directed in the Scoping Memo.

291. It is reasonable to estimate that "small amount" to be $0.150 million, half labor and half non-labor.

292. CS&P productivity benefits include ensuring that highest value projects are implemented.

293. A CS&P forecast of $17.666 million is reasonable.

294. O&M savings for past capital projects are included in recorded data.

295. SCE's forecast of $8.820 million for incremental O&M associated with new software is reasonable.

296. A total O&M forecast of $220.546 million (2012$) is reasonable.

Section 9.2 - Information Technology – Capital

297. Expenditures in 2015 are appropriate as part of planning, designing, and pre-staging the Alhambra Data Center's servers and infrastructure.

298. SCE's $13.6 million 2015 forecast for the Alhambra Data Center is reasonable.

299. SCE's 2015 forecast for Midrange Enterprise Servers Hardware of $39.504 million is reasonable.

300. SCE's need to refresh additional computers was due to delays in 2013 and this need is recurring, adding the 2013 underspend to the original 2014 forecast is reasonable.

301. SCE's 2014 and 2015 forecasts for personal computers of $10.347 million and $9.128 million respectively are reasonable.

302. The need for expanded network capacity to accommodate increased data traffic has existed for several years without resulting in an increase in actual expenditures.

303. Since SCE's spending in transmission network facilities will address expenditures typical for the last five years, ORA's five-year recorded cost average methodology is reasonable.

304. A Transmission Network Facilities forecast of $15.471 million for both 2014 and 2015 is reasonable.

305. SCE's stated desire to expeditiously replace 188 miles of "obsolete" fiber cable has, to date, not been matched by its actions.

306. ORA's 2015 forecast of $1.620 million for cable replacement, based on actual amounts scheduled in 2013 and 2014, is reasonable.

307. It is reasonable to carry forward a portion of SCE's 2013 underspending into 2014.

308. $2.000 million is a reasonable forecast of fiber optic cable replacement in 2014.

309. It is reasonable to approve a forecast of 16 microwave units per year, based on the 2009-2013 average, for each of 2014 and 2015, for a forecast of $2.640 million each year.

310. SCE's forecasts of $4.601 million for 2014 and $14 million for 2015 for mobile radio system replacement are reasonable.

311. ORA's five-year recorded cost average is the most appropriate methodology for risk management disaster recovery, given SCE's failure to differentiate items as "enhancement" or "refresh."

312. ORA's forecast of $2.549 million for both 2014 and 2015 for risk management disaster recovery is reasonable

313. SCE's telecom forecasts are tied directly to their individual projects; i.e. the forecast costs go up or down depending on the number and size of the projects each year.

314. SCE's forecast of telecom costs of $43.046 million for 2014 and $51.756 million for 2015 is reasonable.

Section 9.3 - Information Technology – Capitalized Software

315. Each of the projects in the SAM bundle was approved in the 2012 GRC. Their inclusion in the 2015 GRC reflects reevaluations of the projects and, in some cases, delays in their implementation.

316. The RCMS project was delayed, but the scope was not reduced.

317. SCE overspent its 2013 CMS forecast.

318. ORA's proposal to keep the total CMS project forecast constant is reasonable.

319. A total forecast of $29.396 million in 2014 and $17.215 million in 2015 for SAM bundles is reasonable.

320. SCE's forecast for an increase in cybersecurity and IT compliance is premised entirely on a prior underspend with no other justification.

321. A 2014 forecast of cybersecurity and IT compliance of $17.711 million is reasonable.

322. NERC CIP Version 5 is a significant change in circumstance relative to past years that justifies SCE's budget-based forecast for regulatory mandated capitalized software.

323. The MAP project is necessary for NERC CIP compliance.

324. It is reasonable to carry forward a portion of the MAP underspend in 2013 to 2014 for a 2014 forecast of $6.794 million.

325. SCE's uncontested, revised forecast for financial services is reasonable.

326. Maintenance of SONGS records is necessary despite the SONGS shutdown.

327. SCE's eDMRM forecast of $11.4 million for 2015 is reasonable.

328. SCE's concern regarding violations of CANSPAM and TCPA is well-founded.

329. The benefit-cost ratio of the Digital Experience project is greater than one, even if additional capital costs are included.

330. SCE must invest in ASR to meet customer expectations now and in the future.

331. Funding for ASR is reasonable.

332. SCE's Digital Experience Project forecast of $8.44 million for 2014 and $22.3 million for 2015 is reasonable.

333. SCE's uncontested GMS forecast is reasonable.

Section 10 - Human Resources

334. Cost of service ratemaking principles do not require ratepayers to pay costs that the utility has not shown further the provision of safe and reliable service at just and reasonable rates.

335. SONGS HR staffing peaked at 17 in 2011 and has been higher than four positions from 2008 to 2012.

336. It is reasonable to reduce SCE's forecast for HR department labor expenses in Accounts 920/921 by $0.330 million to $21.118 million.

337. EIC awards are largely given based on shareholder benefits.

338. SCE financial performance may benefit ratepayers, however the ratepayer benefit is much less direct than the shareholder benefit.

339. It is reasonable for ratepayers to fund ~~50~~40% of SCE's EIC request.

340. Other portions of SCE's request for HR department and executive officer compensation request are reasonable.

341. Significant portions of the STIP payout criteria are directly related to shareholder benefits that may or may not provide secondary benefits to ratepayers.

342. STIP payments in 2012, on which SCE bases its proposal, were 27% above target.

343. There is no clear trend in the ratio of STIP payments to total labor costs in 2008-2013, and using a historical average of this value is reasonable.

344. A total 2015 STIP illustrative forecast of $98 million is reasonable.

345. SCE has not demonstrated that LTI furthers the provision of safe and reliable service at just and reasonable rates.

346. SCE's employee recognition programs (Spot bonuses and ACE) promote safety and other behaviors that further the provision of safe and reliable service at just and reasonable rates.

347. The costs of these recognition programs appear reasonable relative to the benefits.

348. SCE's forecast of the employee recognition programs is not transparent.

349. Updating the actuarial calculations due to the changed number of SONGS employees and other information has a small impact relative to pension cost uncertainty.

350. SCE's forecast of pension costs is reasonable.

351. SCE's minimum pension contributions are not under SCE's control.

352. Continuing the two way Pension Cost Balancing Account is appropriate.

353. SCE's 2015-2017 average forecast of PBOP costs and actuarial fees is reasonable.

354. SCE's basic approach of calculating per-eligible-employee costs, escalating those costs, and multiplying by the number of eligible employees to create forecasts for other benefits is reasonable.

355. SCE's medical escalation rate is consistent with information provided by SCE's medical plan administrators.

356. Continuing the two way Medical Program Balancing Account is appropriate.

357. It is reasonable for ratepayers to fund 50% of SCE's Executive Benefits request.

358. The total adopted forecast for pensions and benefits programs in Account 926 is reasonable.

Section 11 - (Safety, Security, and Compliance)

359. SCE's forecast of O&M costs for the Ethics and Compliance department are reasonable.

360. SCE's analysis of transmission environmental services work based on new transmission projects is credible.

361. SCE's forecasts of environmental services for transmission and distribution are reasonable.

362. Health and safety labor expenses have been stable and therefore SCE's forecast based on 2012 recorded is appropriate.

363. SCE's health and safety non-labor forecast is uncontested.

364. SCE's forecast for Health and Safety in Account 925 is reasonable.

365. SCE's forecast of outside consulting services is reasonable.

366. It is appropriate to shift 2015-2017 rate recovery for marine mitigation to expense rather than capitalization.

367. TURN's forecast for ongoing mitigation costs, $3. 703 million (2012$), is reasonable.

368. It is premature to approve costs for a compliance-driven project that is not yet required.

369. It is reasonable to permit SCE and SDG&E to file an application to recover costs in the event that CCC does require additional reef construction, or other measures.

370. ORA's uncontested capital and O&M forecasts for Corporate Security and Business Resiliency are reasonable.

Section 12.1 - Financial Services

371. SCE's forecast for accounts 920/921 is uncontested, except for OpX reductions which we reject.

372. SCE's forecast for accounts 920/921 is reasonable.

373. It is inconsistent for SCE to forecast continuing consulting costs for OpX but not to credit ratepayers with additional savings that will result.

374. TURN's proposed adjustment to remove 50% of Bain & Co costs for forecasting purposes is reasonable.

375. TURN's proposed treatment of vendor discounts reflects a consistent approach to analyzing this account.

376. SCE's proposed 5YA thus includes only two years of vendor discounts, $2.183 million in 2011 and $3.409 million in 2012, and deflates their value in the test year forecast.

377. 2013 data on vendor discounts is more reflective of current conditions than earlier years' data, since 2013 data captures benefits of OpX not otherwise credited to ratepayers in SCE's approach.

378. It is reasonable to remove vendor discounts from the 5YA using TURN's method.

379. TURN's unopposed proposal to remove $8.9 million in 2009 tax consulting costs from the five-year average (resulting in a $1.9 million TY reduction) is reasonable.

Section 12.2 - Audit Services Department (ASD)

380. Recorded data from 2013 and early 2014 suggest significant declines in affiliate credits following the EME bankruptcy.

381. TURN's approach of forecasting ASD expenses based solely on utility-only costs is a reasonable approach to forecast costs in light of the bankruptcy.

382. TURN's forecast of ASD expenses, $7.721 million in Accounts 920/921, is reasonable.

Section 12.3 - Property and Liability Insurance

383. SCE's uncontested forecast of property insurance in Account 924 of $18.973 million is reasonable.

384. It is reasonable to expect that the total liability insurance forecast would decline with the number of total employees.

385. ORA's forecast of liability insurance in Account 925 of $70.335 million is reasonable.

Section 12.4.1 - Law

386. SCE's forecast for Accounts 920 and 921 for in-house costs of $30.539 million is reasonable.

387. ORA's proposal to reject SCE's incentive payments to outside counsel is reasonable because SCE has not demonstrated that it is obtaining base fees at discount compared to market.

388. Absent a finding of error or fault, it is reasonable to include costs related to litigation resulting from fires.

389. The recorded figures for outside counsel costs during the 2010-2011 period reflect largely unexplained and unjustified increases as compared to the 2008-09 period.

390. It is reasonable to exclude 2010-2011 from the forecast of outside counsel expenses.

391. A forecast of $12.503 million for outside council is reasonable.

392. The primary functions of the Board include representing the interests of shareholders.

393. It is reasonable to subtract $998,095 from SCE's 2015 test year forecast of corporate governance in Account 930.

Section 12.4.2 - Claims

394. It is reasonably necessary for SCE to have access to secure space to store evidence.

395. A total forecast for administrative and general functions of the Claims Department in Accounts 920/921/924 of $3.658 million is reasonable.

396. A 5YA forecast is a reasonable approach to forecasting accounts with high variation in recorded costs.

397. SCE's forecast of $19.424 million for Account 925, Claims Reserves is reasonable.

Section 12.4.3 – Workers' Compensation

398. Workers' compensation claims have declined significantly since 2008.

399. It is reasonable to expect that remaining adjustments to 2013 recorded data will be small.

400. It is reasonable to use a 5YA of 2009 to 2013 to forecast workers's compensation reserves in Account 925.

401. A total forecast of workers' compensation costs in Account 925 of $15.903 million (2012$) is reasonable.

Section 12.5.1 and 12.5.2 – Operational Services Other than CRE

402. SCE's uncontested TY O&M forecasts of $7.339 million for PPO and $1.835 million for SDD are reasonable.

403. SCE's capital expenditure forecast for non-CRE OS projects from 2014-2015 totaling $12.952 million is uncontested and is reasonable.

Section 12.5.4 - CRE O&M

404. TURN's 3YA forecast approach, including adjustments for OpX is reasonable.

405. It is reasonable to increase TURN's forecast by $0.400 million in non-labor to account for affiliate credits and cost centers excluded by TURN's 2013 estimate.

406. The forecast of $11.115 million, as agreed by SCE and TURN and uncontested by other parties, is reasonable for Account 931.

407. Given the level of variation in recorded data in Account 935, SCE's 3YA is appropriate.

Section 12.5.5 – CRE Capital

408. It is reasonable to calculate a disallowance factor of 9.5% based on SCE's inadequately supported $12.943 million in project management and $12.904 million in contingency compared to its total capital forecast of $271.665 million.

409. It is reasonable to apply this disallowance factor to approved CRE capital projects.

410. The EOC serves an important function separate from the TSD and beyond the intent of the interim EOC.

411. SCE's 2015 capital forecast for the EOC, as adjusted, is reasonable.

412. It is reasonable to require SCE to make a showing in the next GRC that the interim EOC remains used and useful.

413. SCE's 2014-2015 capital forecast for the GO2 Conference and Training Center, as adjusted, is reasonable.

414. It is reasonable to require SCE to make a showing in the next GRC that includes a cost-benefit analysis of the GO2 Conference and Training Center.

415. The number of employees now anticipated to move to IBC is 27-30% below SCE's initial forecast.

416. It is reasonable to expect reduced costs given the change in use (both number and type of employees) of IBC, but some portion of the costs are not dependent on these factors.

417. It is reasonable to reduce SCE's forecast for the IBC by 15%.

418. TURN's proposal to expense costs associated with the Rancho Cucamonga Office Building Optimization is reasonable.

419. It is reasonable to approve a $0.995 million (2015$) O&M expense for the Rancho Cucamonga Office Building Optimization.

420. SCE's capital maintenance forecast is lower than the most conservative scenario developed by Parsons (SCE's contractor).

421. SCE's 2014-2015 capital maintenance forecast, as adjusted, is reasonable.

422. SCE's uncontested explanation for the apparent increase in per-person furniture modification costs (that costs previously forecast elsewhere are now included) is logical.

423. SCE's ongoing furniture modification forecast, as adjusted, is reasonable.

424. Based on our review of SCE's forecast for the energy efficiency blanket and the benefits of the specific projects here, we find that SCE's forecast, as adjusted, is reasonable.

425. SCE has declined to implement garage infrastructure upgrades that were previously authorized by the Commission.

426. It is reasonable to remain skeptical that the full amount that SCE has forecasted would, in fact, actually be spent on the garage infrastructure upgrade program during the 2014-2015 cycle, rather than being redirected into other purposes deemed by SCE to have higher priority.

427. Some actual work on portions of garage upgrades has already at least commenced, and SCE may implement at least some level of spending on the garage upgrades during the 2014-2015 cycle.

428. It is reasonable to approve 50% of SCE's request for the garage upgrades.

429. SCE sought and received in excess of $100 million cumulatively in the 2009 and 2012 GRCs for the same type of service center upgrade work SCE claims is now essential, yet SCE spent zero during the 2009 GRC cycle and $650,000 in 2013.

430. Planning and permitting for work at the Bishop, Kernville, Redlands, Ontario, and Ridgecrest Service Centers has already commenced, and SCE currently projects spending approximately $23 million.

431. The average age of the service centers under SCE's program is 51 years old.

432. It is important to maintain service center facilities over time.

433. Using the final FCI scores and the consultant's grading scale, all of the scored service centers are currently in "fair" condition except for Bishop and San Joaquin.

434. TURN's forecast for service center upgrades is reasonable.

435. SCE's explanation that the IT spend for the projects it used to calculate the IT adder are representative of the projects it requests in this GRC is reasonable.

436. SCE's proposed 12% IT adder is reasonable.

Section 13.1 Corporate Communications

437. SCE's use of 2012 recorded as a baseline for Account 920/921 follows prior Commission guidance and is reasonable.

438. SCE's uncontested forecast of $0.847 million for FERC Account 923 for communication measurement and ethnic media services is reasonable.

439. SCE's explanation of the adjustments in baseline costs for Account 930 due to reorganization is reasonable, and the education expenses outweigh the decline in annual report costs.

440. SCE's proposed 5YA is a reasonable baseline for Account 930.

441. TURN's recommendation to reduce the forecast for the Public Safety Around Electricity Education Campaign by $1.569 million, and thereby limit ratepayer funding to 2012 levels of $6.641 million is reasonable.

442. One of the goals of the Summer Readiness campaign is increasing enrollment in DR programs.

443. The Summer Readiness campaign appears to duplicate other programs.

444. The Corporate Responsibility Report is institutional advertising and it would not be reasonable to include this in our adopted forecast.

Section 13.2 - Corporate Membership Dues and Fees (Account 930.2)

445. SCE ratepayers do receive some valuable benefits through EEI, including information and mutual assistance.

446. It is reasonable to forecast to $1.000 million to account for these benefits without unnecessarily contributing to EEI political activities.

Section 13.3 - Integrated Planning and Environmental Affairs (IP&EA)

447. SCE's forecast of $6.227 million for groups in Integrated Planning that record labor and non-labor expenses to FERC Account 557 is uncontested and is reasonable.

448. It is reasonable to undertake a periodic review of the amount of non-labor costs in Account 549, notwithstanding its review in the PDDMA and ERRA proceedings.

449. Non-labor expenses in Account 549 have fluctuated over the five recorded years, and a 5YA of $2.589 million is a reasonable forecast for non-labor.

450. SCE's request to modify the PDDMA to record only non-labor costs is reasonable.

451. SCE's uncontested labor forecast in Account 549 is reasonable.

452. SCE's forecast for Account 920/921 is uncontested, accept for a reduction related to membership dues adopted above.

453. A forecast of $2.971 million for Account 920/921 is reasonable.

Section 13.4 Regulatory Operations and Regulatory Policy & Affairs (RP&A)

454. Apparent one-time non-labor costs were the result of an accounting change and actually represent normal costs, not one-time NERC costs.

455. SCE's revised non-labor forecast is reasonable.

456. SCE's revised labor forecast is undisputed, and we find it reasonable.

Section 13.5 - LPA

457. It is reasonable to conclude that some training supports shareholder benefits given the relative time allocations from the tracking study.

458. Many of the training topics can reasonably benefit shareholders.

459. It is reasonable to allocate additional costs for general skill-building trainings to shareholders in Account 920/921, as calculated by SCE.

460. TURN's proposed $0.308 million reduction to SCE's non-labor forecast for Account 920/921 is reasonable.

461. SCE's gross labor forecast, based on LRY with incremental positions, is reasonable given the trend in recorded costs and its explanation of the need for new positions.

462. Given the trend in expenses, SCE's non-labor forecast based on LRY with adjustments is reasonable.

463. Other cities may begin to charge BLTs.

464. $0.575 million is a reasonable forecast of BLTs.

465. SCE's other uncontested External Affairs forecasts are reasonable.

Section 14 – Ratemaking

466. SCE's forecast of capital expenditures in the MRTUMA is reasonable.

467. The MRTUMA can be eliminated.

468. SCE's uncontested request to transfer the final 2014 RSDMA balance to BRRBA for recovery in distribution rates is reasonable.

469. SCE's request to eliminate the ESCBA and SOMA is reasonable.

470. It is reasonable to extend the RSDMA through 2017.

Section 15 – Jurisdictional Allocation

471. SCE's uncontested jurisdictional allocation factors are calculated according to methods we have approved in the past and are reasonable.

Section 16

472. SCE's PDL model maintains the historical and intuitive correlation between housing starts and new meters.

473. SCE's PDL model outperforms ORA's model in an extended validation period.

474. TURN's adjustment to update SCE's PDL model for the most recent available data is appropriate.

475. TURN's forecast of new Residential and Non-Residential meters is reasonable.

476. SCE's forecast of new Agricultural meters is reasonable.

477. It is reasonable to adjust SCE's forecasts of retail sales and number of customers based on the adopted forecast of new meters.

Sections 17-20

478. SCE's total OOR forecast of approximately $201 million in 2015 is reasonable.

479. It is appropriate to prioritize an audit of NTP&S.

480. SCE's uncontested cost escalation method is reasonable.

481. Attrition year revenue increases give SCE an opportunity to offset some inflationary price increases, increase capital investments, and earn its authorized rate of return in the attrition years.

482. An appropriate PTYR mechanism is simple; accurately aligns with how costs are incurred for the utility; and gives the utility an incentive to manage costs while enhancing productivity.

483. Global Insight escalation rates are a reasonable forecast of the inflationary increases for O&M labor costs.

484. SCE's estimates PTYR escalation rates for other O&M expenses are reasonable.

485. Escalating capital additions by 2% per year is appropriate.

486. The following escalation rates are reasonable:

Category		2016	2017	Notes
O&M - Labor				
	Disability Programs	2.30%	2.60%	Global Insight
	Executive Benefits	2.30%	2.60%	Global Insight
	401(k)	2.30%	2.60%	Global Insight
O&M - Other				
	Medical	8.00%	8.00%	SCE Estimate
	Dental	4.50%	4.50%	SCE Estimate
	Vision	2.00%	2.00%	SCE Estimate
	Group Life	0.00%	0.00%	SCE Estimate
	Misc. Benefit	3.03%	2.90%	SCE Estimate
Capital Additions		2.00%	2.00%	Applied to 2015 capital additions, based on 2015 authorized capital expenditures

487. SCE's Z-factor mechanism is reasonable.

488. SCE's proposal to implement PTYR updates by advice letter is reasonable.

489. The adopted PTYR mechanism strikes an appropriate balance between the goals described above as well as the parties' different positions.

490. SCE's uncontested method for converting capital expenditures to Plant-In-Service is reasonable.

Section 21.2

491. SPR results for Account 355 support a 50 R0.5 life curve.

492. SPR results for Account 353 support a 45 R0.5 life curve.

493. The longer experience bands for Account 354 support a 65 R5.

494. SPR results for Account 356 support a 61 R3.

495. SCE's engineering analysis of assets in Account 362 supports the 45 R1.5 curve.

496. SCE's engineering analysis of assets in Account 364 supports the 47-year ASL proposed by TURN and ORA.

497. SPR results for Account 364 support a 47 L0.5 life curve.

498. SCE's engineering analysis of assets in Account 367 supports an increase in ASL.

499. SPR analysis suggests an R0.5 curve for Account 367.

500. A 45 R0.5 curve for account 367 is a reasonable compromise.

501. SCE's engineering analysis of assets in Account 368 supports the 33 R1 curve.

502. SPR results for Account 369 support a 45 R1.5.

503. SCE's operational data for assets in Account 373 supports a 40 L0.5.

504. The adopted life curves are reasonable.

Section 21.3

505. SCE's recorded NSR data supports its proposed increase to -35% NSR for Account 352.

506. SCE's recorded NSR data supports its proposed increase to -15% NSR for Account 353.

507. SCE's recorded NSR data for Account 354 is based on a small sample which may not be representative.

508. Industry NSR data for Account 354 supports a decrease in NSR to -60%.

509. It is likely that per unit COR for Account 355 may decrease in the future.

510. Declining per unit COR for Account 355 supports an NSR of -72%.

511. Industry NSR data for Account 356 supports retaining the current -80% NSR.

512. SCE's recorded NSR data supports an increase in NSR for Account 362, but future changes in the retirement mix suggest that the NSR should not be increased to more than -25%.

513. SCE's recorded NSR data supports an increase in NSR for Account 364.

514. SCE's recorded NSR data supports an increase in NSR for Account 365.

515. SCE's recorded NSR data and extended ASL support an increase in NSR for Account 366.

516. SCE's recorded NSR data supports its proposed increase to -20% NSR for Account 368.

517. SCE's recorded NSR data supports an increase in NSR for Account 369.

518. SCE's recorded NSR data supports an increase in NSR for Account 373.

519. The adopted NSRs are reasonable.

Section 21.4

520. SCE's unchanged service life estimates for hydro and Pebbly Beach were found reasonable in the 2012 GRC and are unchallenged.

521. SCE's service life estimate for Palo Verde includes the benefit of the extended operating license for the plant. No party challenges this estimate.

522. SCE's service life estimates for hydro, Pebbly Beach, and Palo Verde are reasonable.

523. TURN's 35-year life estimate for the Peakers is consistent with industry comparisons and SCE's workpaper estimates.

524. TURN's 35-year life estimate for the Peakers is reasonable.

525. TURN's 35-year life estimate for Mountainview is consistent with industry comparisons and SCE's workpaper estimates.

526. TURN's 35-year life estimate for Mountainview is reasonable.

527. ORA's proposed 25-year life estimate for Solar PV is supported by panel manufacturers' warranties and SCE's website claims.

528. ORA's proposed 25-year life estimate for Solar PV is reasonable.

Section 22.2 – Safe Harbor Method for Repairs

529. As a result of SCE's 2012 tax election: SCE's shareholders received $321 million in savings during 2012-2014 relative to forecast tax expense. The tax savings equates to $542 million (nominal$) in revenue requirement if ratepayers had received the savings instead. SCE ratepayers will pay $294 million (net present value $741 million nominal$) of increased tax revenue requirement.

530. Revenue Proceeding 2011-43, which authorized the tax election, was published in August 2011.

531. In February 2012, SCE published its 2011 annual report, which contained a representation to the Securities and Exchange Commission and investors that SCE would elect the safe harbor.

532. SCE's 2012 GRC proceeding was ongoing when SCE published its 2011 annual report.

533. SCE did not bring its change in tax accounting to our attention.

534. A ratebase offset remedy is prospective, not retroactive.

535. A ratebase offset of $344.026 million, applied in 2015, will reasonably compensate ratepayers for their increased future costs attributable to SCE's safe harbor tax election.

536. It is reasonable to adopt a ratebase offset of $344.026 million, applied in 2015.

Section 22.3 – Advanced Meters

537. SCE changed the tax depreciation schedule of advanced meters installed during 2012 after the AMI Balancing Account was closed at the end of 2012.

538. As a result of SCE's change, ratepayers would pay 100% of the costs of the meters, but receive only 66% of the state tax depreciation.

539. TURN's proposed remedy to reduce SCE's state income tax by $2.090 million, less a $0.731 million increase in federal taxes per year during 2015-2017, is solely prospective.

540. It is reasonable to adopt TURN's proposed remedy.

Section 22.4 – Updates to Tax Forecast in SCE-76

541. SCE-76 makes two significant decrease to SCE's forecast revenue requirement: a revised estimate of tax repair deductions from Pole Programs 2015-2017 and a change in allocation formula between CPUC and FERC jurisdictions.

542. The combined test year 2015 revenue requirement of these two changes is $201 million.

543. The net present value of the changes during 2015-2017 is $598 million.

544. No party opposed SCE's position on these tax changes.

545. The revenue requirement reductions will not result in any offsetting cost increase to ratepayers (FERC jurisdiction included) during this GRC period.

546. SCE did not present analysis of periods further into the future.

547. It is unlikely, but not impossible, that future costs would be great enough to offset benefits during 2015-2017, on a net present value basis.

548. It is reasonable to adopt SCE's tax changes proposed in SCE-76.

Section 22.6 – Policy Considerations

549. In a post-hearing exhibit, SCE noted a 2014 tax depreciation increase of $874 million due to the enactment of the Tax Increase Prevention Act of 2014 (TIPA). SCE did not elaborate and no other party addressed it.

550. It is unclear from the record whether the benefits of the change due to TIPA were flowed-through to shareholders and if there will be a cost increase for ratepayers.

551. It is reasonable to create a two-way Tax Accounting Memorandum Account to track all tax changes during this GRC period.

Section 23 – Rate Base

552. There is considerable variation in the year-to-year trend in customer advances.

553. An adjustment based on 2013 actual customer advances balance is appropriate.

554. TURN's proposal to "shift" the 2015 customer advance balance upward by the amount of the variance in 2013 is reasonable.

555. SCE's regression analysis of T&D M&S is consistent with those approved in past decisions, shows a strong correlation, and is, thus, reasonable.

556. It is reasonable to apply the M&S forecast approach to the adopted capital expenditures instead of SCE's forecast.

557. A total M&S forecast of $116.948 million (nominal$) in 2015 is reasonable.

558. It is reasonable to exclude minimum cash balances that are not mandated by banks from working cash.

559. It is reasonable to exclude SCE's $5.7 million forecast for LTIP related working cash from rate base.

560. Years with minimal or negative tax payments may not be indicative of 2015; these years should not be unduly weighted.

561. A five-year weighted average is reasonable to calculate both state and federal income tax lag days.

562. A $103.360 million reduction to rate base relative to SCE's proposal for income tax lag is reasonable.

563. SCE's proposals, including modifications proposed by TURN and uncontested by SCE, for other aspects of working cash lead lag study are reasonable.

564. It is reasonable to continue existing policy for SCE with respect to customer deposits as an offset to rate base.

565. It is reasonable to offset SCE's rate base by $180.269 million, or 90% of customer deposits.

566. It is reasonable for SCE to charge an offsetting interest expense based on the three-month commercial paper interest rate for the rate base offset of customer deposits.

567. It is reasonable to approve the continued 10% of customer deposits for the community banking program and for SCE to deposit up to $20.030 million in this manner.

568. SCE's uncontested proposed AFUDC rates are reasonable.

Section 25

569. SCE's phrase "add to fully staff" refers to shifting existing employees into vacancies during the OpX reorganization, not adding additional positions.

570. It is reasonable to credit ratepayers with 75 percent of forecast OpX savings for IT and customer service, net of adjustments for capitalization and additional expenses.

Section 26 - Joint Proposal on Accessibility Issues

571. Due to the fact that the parties propose a new program that potentially includes costs across a wide variety of organizations within SCE, it is reasonable to accept this vague forecast, but only on a temporary basis.

572. SCE and CforAT's joint forecast of $1.5 million for accessibility issues is reasonable.

Section 27 - Settlements

573. The settlement between SCE and JMP is reasonable in light of the whole record, consistent with law, and in the public interest.

574. The settlement between SCE and Cal-SLA is not directly relevant to this proceeding.

Section 28 - Other Issues

575. A modest recognition program, using gear with the SCE name and logo, is a reasonable means to motivate employees to perform well.

576. It is reasonable to adopt TURN's proposal in part and reduce gross plant by $0.324 million (2015 weighted average).

577. The remaining O&M funding is reasonable to allow SCE to use this recognition approach to motivate employees to benefit ratepayer interests.

Conclusions of Law

Section 6

1. SCE's forecasts of O&M and capital expenditures for power procurement should be approved.

2. SCE's unopposed forecast of $0.308 million in O&M for Mohave Generating Station should be approved.

3. The Mohave Balancing Account should be closed.

4. A total hydro O&M forecast of $52.849 million should be approved.

5. SCE's uncontested revised rebuttal forecast for hydro capital should be approved. The forecast is ($ millions, nominal):

2014	2015
71.149	90.231

6. A total O&M forecast of $48.338 million for Mountainview, in FERC Accounts 549 and 554, should be approved.

7. For Mountainview capital expenditures, the unopposed SCE and ORA recommended forecast of $1.327 million, and $1.131 million for 2014 and 2015 respectively should be approved.

8. A total Peakers O&M forecast of $10.155 million should be approved.

9. SCE's capital expenditures request of $2.954 million in 2014 and $3.043 million in 2015 for the Peakers is reasonable

10. A total forecast of $3.503 million for SPVP O&M should be approved. Added facilities costs should not be subject to escalation.

11. SCE's termination payment to SunPower should be disallowed.

12. SCE's SPVP capital expenditure request of $0.425 million for 2014 and $1.035 million for 2015 should be approved.

13. SPVPBA should be eliminated.

14. TURN's forecast of $4.360 million in O&M for Catalina should be approved.

15. SCE should be allowed to recover AFUDC and capitalized property taxes through the end of 2013, in addition to $5.1 million in capital expenditures recorded by that time.

16. A total O&M forecast of $0.546 million should be approved for the fuel cell program.

17. The FCPMA should be eliminated.

Section 7.1

18. SCE's proposed core RIIM capital categories WCR, Underground Cable Life, CIC Replacement, Underground Switch, Underground Structure Replacement, Circuit Breaker Replacements, and Substation Transformer Replacement} should be adopted.

19. SCE's proposed High Priority RIIM categories (customer growth, storms, and claims) should be adopted.

20. SCE's proposed RIIM staffing target proposal (2,225 employees in the categories identified at SCE-3V1 at 27) should be adopted.

21. The TURN/CUE proposal for the mechanics of the SRIIM capital spending mechanism should be adopted with the following modifications. Overspending in the High Priority categories can offset underspending in the core SRIIM categories if two conditions are true: the overspending in High Priority categories exceeds ten percent of the adopted forecast for those categories and SCE's actual rate of return on rate base for the period does not exceed the authorized rate of return. The first ten percent of overspending on High Priority categories cannot be used to offset underspending in the core SRIIM categories under any circumstance.

Section 7.2

22. SCE's CRAS capital expenditure request for 2013 should be approved; SCE should be allowed to reapply for later years' capital expenditures.

23. $51.058 million of SCE's O&M request for Engineering and Grid Technology should be approved.

24. Engineering and Grid Technology capital expenditures should be approved as follows ($000s): $40,217 in 2014 and $31,681 in 2015.

25. A total forecast of O&M in Account 583.120 of $23.173 million should be approved.

26. SCE's forecasts for O&M in Accounts 593.120 and 594.120 should be approved.

Section 7.3

27. SCE's forecasts for uncontested transmission planning projects should be approved.

28. SCE's forecast for the Victor Substation should be approved.

29. SCE's forecasts for other transmission planning projects should be approved.

30. SCE's forecast of A-bank plan expenses for 2014-2015 should be approved.

31. SCE's forecast of subtransmission line plan expenses for 2014- 2015 should be approved.

32. SCE's DSP forecast for 2014-2015 should be approved.

33. Funding for 60 circuit breaker replacements per year, or $9.887 million should be approved.

34. SCE's forecast for the DSP circuit work category should be approved.

35. SCE's forecasts for Capacitor and Circuit Automation Programs should be approved.

36. SCE's forecasts for Distribution Plant Betterment, Distribution VAR Plan, and Substation Load Information Monitoring should be approved.

37. SCE's 2014-2015 forecast for Generator Interconnection Program should be approved.

38. SCE's 2014-2015 forecast for Added Facilities Projects should be approved.

Section 7.4

39. A total forecast for underground cable programs of (millions of nominal$) $140.481 in 2014 and $206.616 in 2015 should be approved.

40. A total forecast for A-bank transformer replacements of (millions of nominal$) $14.417 in 2014 and $14.798 in 2015 should be approved.

41. A total forecast for distribution circuit breaker replacement of (millions of nominal$) $24.016 in 2014 and $24.366 in 2015 should be approved.

42. ORA's uncontested forecast for B-bank transformer replacements should be approved.

43. SCE's uncontested forecasts for 4kV Circuit replacement programs should be approved.

44. SCE's uncontested forecasts for other infrastructure replacement programs should be approved.

Section 7.5

45. The methods adopted for calculating customer driven expenses and expenditures should be applied to the forecast of new meters and other items adopted in this decision, instead of any party's forecast of those values.

46. The total O&M forecast for Customer-Driven Programs and Distribution Construction of $15.609 million should be approved.

47. The following total capital forecast for disputed items in Customer-Driven Programs and Distribution Construction (including transformers and

prefabrication) should be approved: $384.259 million in 2014 and $497.795 million in 2015 (nominal$).

Section 7.6

48. The following forecast of O&M as follows for underground structures should be approved (millions of 2012$):

	Requested		Approved	
Account	583.120	593.120	583.120	593.120
Labor	4.523	1.669	4.523	1.335
Non-Labor	1.678	14.964	1.678	11.971
Total	6.201	16.633	6.201	13.306

49. The following forecast of capital expenditures for underground structure replacement should be approved (millions of nominal $):

	2014	2015
Requested	$ 67.500	$ 67.500
Approved	$ 54.000	$ 54.000

50. SCE's uncontested distribution maintenance capital and O&M forecasts should be approved.

51. SCE's uncontested forecast of JPO expenses based on LRY should be approved.

52. A forecast of $4 million for joint pole credits is reasonable.

53. SCE should undertake a review of joint pole credits and present information in its next GRC on its efforts to ensure that SCE ratepayers are not unduly subsidizing other companies' use of jointly owned poles.

54. SCE's forecasts for the uncontested elements of Accounts 593.120 and 594.120 should be approved.

55. SCE's forecast unit costs of transmission and distribution pole replacements should be reduced by 3%.

56. SCE's forecast of deteriorated pole replacements should be approved.

57. The following forecast of aged pole replacements should be approved:

Aged Pole Replacements		2014	2015
Poles Replaced	Adopted	8,000	0
	Requested	14,500	1,898
Nominal$, millions	Adopted	98.576	0
	Requested	184.189	24.622

58. SCE's uncontested forecast of $100 per wood pole disposal should be approved.

59. SCE's Distribution Inspection and Maintenance capital expenditure forecasts that are not specifically addressed are uncontested and should be approved.

60. SCE's request to close the Bark Beetle CEMA should be approved.

Section 7.7

61. A total forecast for PLP O&M of $36.052 million should be adopted.

62. Cost sharing in proportion to the contribution to pole overloading is not unduly discriminatory or anticompetitive.

63. The following PLP capital forecast should be adopted.

	SCE		Adopted	
	2014	2015	2014	2015
Pole Replacements - Distribution	$33.916	$288.636	$32.899	$189.765
Pole Replacements - Transmission	$6.789	$58.080	$6.585	$38.186
Malibu adjustment		$(5.130)	$ -	$(5.130)
Distribution	$1.371	$11.668	$1.371	$7.909

Transformers				
Prefabrication	$0.931	$7.926	$0.931	$ 5.372
Joint Pole - Distribution	$(2.360)	$(20.083)	$(2.360)	$(13.612)
Joint Pole - Transmission	$(0.289)	$(2.476)	$(0.289)	$(1.678)
Wood Pole Disposal	$0.314	$2.674	$0.314	$1.812
Total	$40.672	$341.295	$39.452	$222.624

64. SCE should be authorized to establish the PLPBA including deteriorated pole replacements and with a 15% cap on costs above the adopted forecast. The 15% cap should apply to 2016 and 2017 only.

Section 7.8

65. A total Grid Operations O&M forecast of $111.801 million (2012$) should be adopted.

66. The following forecast of Grid Operations Capital should be adopted.

(millions of nominal$)		2014	2015
Storm		$ 47.084	$ 48.110
	Transmission	$ 4.562	$ 4.683
	Substation	$ 0.316	$ 0.325
	Distribution	$ 42.206	$ 43.102
Streetlights		$ 38.872	$ 36.564
	Pole Replacement	$ 24.505	$ 25.025
	Luminaire Replacement	$ 12.273	$ 9.400
	Breakdown Maintenance	$ 2.094	$ 2.139
Operational Facilities Maintenance		$ 5.600	$ 5.749
Total		$ 91.556	$ 90.423

Section 7.9-7.11

67. A total transmission and substation maintenance O&M forecast of $84.739 million (2012$) should be approved.

68. A total transmission and substation maintenance capital forecast of $121.636 million (nominal$) in 2014 and $131.865 million in 2015 should be approved.

69. A total forecast of $65.912 million (2012$) for T&D Safety, Training and Environmental Programs should be adopted

70. A total forecast for operational support and other costs of $64.505 million (2012$) should be adopted.

71. A total forecast of OOR of $128.369 million (2012$) should be adopted.

Section 8

72. A total O&M forecast for Customer Service of $135.337 million, excluding uncollectibles, should be adopted.

73. A total MSO capital forecast of $13.977 million in 2014 and $16.483 million in 2015 should be adopted.

74. SCE's BCD capital forecast should be adopted.

75. A total Customer Service OOR forecast of $28.731 million is reasonable.

Section 9

76. A total O&M forecast of $220.546 million (2012$) should be approved.

77. SCE's $13.6 million 2015 forecast for the Alhambra Data Center should be approved.

78. SCE's 2015 forecast for Midrange Enterprise Servers Hardware of $39.504 million should be approved.

79. SCE's forecast of personal computers should be approved.

80. Since SCE's spending in transmission network facilities will address expenditures typical for the last five years, ORA's five-year recorded cost average methodology should be approved.

81. A Transmission Network Facilities forecast of $15.471 million for both 2014 and 2015 should be approved.

82. ORA's 2015 forecast of $1.620 million for cable replacement, based on actual amounts scheduled in 2013 and 2014 should be approved.

83. A $2.000 million forecast of fiber optic cable replacement in 2014 should be approved.

84. A forecast of $2.640 million each year for microwave units should be approved.

85. SCE's forecasts of $4.601 million for 2014 and $14 million for 2015 for mobile radio system replacement should be approved.

86. ORA's forecast of $2.549 million for both 2014 and 2015 for risk management disaster recovery should be approved.

87. SCE's forecast of telecom costs of $43.046 million for 2014 and $51.756 million for 2015 should be approved.

88. A total forecast of $29.396 million in 2014 and $17.215 million in 2015 for SAM bundles should be approved.

89. A 2014 forecast of cybersecurity and IT compliance of $17.711 should be approved.

90. A 2014 MAP forecast of $6.794 million should be approved.

91. SCE's uncontested, revised forecast for financial services should be approved.

92. SCE's eDMRM forecast of $11.4 million for 2015 should be approved.

93. SCE's Digital Experience Project forecast of $8.44 million for 2014 and $22.3 million for 2015 should be approved.

94. SCE's uncontested GMS should be approved.

Section 10

95. Ratepayers should not pay costs that the utility has not shown further the provision of safe and reliable service at just and reasonable rates.

96. A total STIP illustrative forecast of $98 million should be approved.

97. No rate recovery of LTI should be approved.

98. A total forecast for pensions and benefits programs in Account 926 should be approved.

99. The following two-way balancing accounts should continue: Pension Cost Balancing Account and Medical Program Balancing Account.

Section 11

100. SCE's forecast of O&M costs for the Ethics and Compliance department should be approved.

101. SCE's forecasts of environmental services for transmission and distribution should be approved.

102. SCE's forecast for Health and Safety in Account 925 should be approved.

103. SCE's forecast of outside consulting services should be approved.

104. TURN's forecast for ongoing mitigation costs, $3.703 million (2012$), should be approved.

105. The utilities should not permitted to recover any cost twice. If a cost permitted for recovery here is also recovered from the nuclear decommissioning trust (or any other source), SCE and SDG&E should be required to refund the revenue requirement associated with that cost to ratepayers, with interest.

106. SCE and SDG&E should be authorized to file an application to recover costs in the event that CCC does require additional reef construction, or other measures.

107. ORA's uncontested capital and O&M forecasts for Corporate Security and Business Resiliency should be approved.

Section 12

108. SCE should be required to make a showing in the next GRC that the interim EOC remains used and useful, or the undepreciated balance should be removed from rates.

109. A total O&M forecast of $296.317 million (2012$) should be adopted for FL&OS.

110. The following capital forecast should be adopted for FL&OS: $78.400 million in 2014 and $86.098 million in 2015 (nominal$).

Section 13

111. A total O&M forecast of $65.021 million (2012$) should be adopted for External Relations.

112. SCE's request to modify the PDDMA to record only non-labor costs should be approved.

Section 14

113. The MRTUMA should be eliminated.

114. SCE should be authorized to transfer the final December 31, 2014 balance of RSDMA to BRRBA for recovery in distribution rates as part of its advice letter filing implementing this decision.

115. The RSDMA should be extended through 2017.

116. SCE's request to eliminate the ESCBA and SOMA should be approved.

Section 15

117. SCE's uncontested jurisdictional allocation factors should be approved.

Section 16

118. TURN's forecast of new Residential and Non-Residential meters should be approved.

119. SCE's forecast of new Agricultural meters should be approved.

120. SCE's forecasts of retail sales and number of customers, as adjusted based on the adopted forecast of new meters, should be approved.

Sections 17-20

121. SCE's total OOR forecast of approximately $201 million in 2015 should be adopted.

122. An audit of NTP&S should be conducted.

123. SCE's uncontested cost escalation method should be adopted.

124. The following PTYR escalation rates should be adopted:

Category		2016	2017	Notes
O&M - Labor				
	Disability Programs	2.30%	2.60%	Global Insight
	Executive Benefits	2.30%	2.60%	Global Insight
	401(k)	2.30%	2.60%	Global Insight
O&M - Other				
	Medical	8.00%	8.00%	SCE Estimate
	Dental	4.50%	4.50%	SCE Estimate
	Vision	2.00%	2.00%	SCE Estimate
	Group Life	0.00%	0.00%	SCE Estimate
	Misc. Benefit	3.03%	2.90%	SCE Estimate
Capital Additions		2.00%	2.00%	Applied to 2015 capital additions, based on 2015 authorized capital expenditures

125. SCE's Z-factor mechanism should be adopted.

126. SCE's proposal to implement PTYR updates by advice letter should be adopted.

127. SCE's uncontested method for converting capital expenditures to Plant-In-Service should be adopted.

Section 21

128. The adopted life curves, summarized in the following table, are reasonable.

Account		Approved Life Curve
353	Station equipment	45 R 0.5
354	Towers & Fixtures	65 R 5
355	Poles & Fixtures	50 R 0.5
356	Overhead Conductors & Devices	61 R 3
362	Station Equipment	45 R 1.5
364	Poles, Towers & Fixtures	47 L 0.5
367	Underground Conductors & Devices	45 R 0.5
368	Line Transformers	33 R 1
369	Services	45 R 1.5
373	Street Lighting & Signal Systems	40 L 0.5

129. The adopted NSRs, summarized in the following table, are reasonable.

Account			Approved NSR
Transmission Plant			
352	-	Structures and Improvements	-35%
353	-	Station Equipment	-15%
354	-	Towers and Fixtures	-60%
355	-	Poles and Fixtures	-72%
356	-	Overhead Conductors & Devices	-80%
Distribution Plant			
362	-	Station Equipment	-25%
364	-	Poles, Towers and Fixtures	-210%
365	-	Overhead Conductors & Devices	-115%
366	-	Underground Conduit	-30%
367	-	Underground Conductors & Devices	-60%
368	-	Life Transformers	-20%
369	-	Services	-100%
373	-	Street Lighting & Signal Systems	-30%

130. SCE's service life estimates for hydro, Pebbly Beach, and Palo Verde should be approved.

131. TURN's estimated service lives of 35 years for the Peakers and for Mountainview should be approved.

132. ORA's proposed 25-year life estimate for Solar PV should be approved.

Section 22

133. The facts of Re Southern California Gas Co., D.92-08-007 (SoCalGas) and Re Southern California Water Co., D.93-04-046 (SoCal Water) are distinguishable from SCE's safe harbor repair deduction because they concern requests to modify the authorized tax expense for past years and the changes were not addressed in GRCs that set rates for the applicable years.

134. The Commission has the authority to address the future implications of tax strategies developed for past tax years.

135. The adopted ratebase offset is not retroactive ratemaking because it is solely prospective.

136. Unlike Pacific Telephone, the change has been discussed directly in the record of this proceeding to set prospective rates to be in force only after a hearing.

137. We frequently consider past events in setting general rates. The mere fact we consider past events in setting rates prospectively does not make this "retroactive ratemaking."

138. A ratebase offset does not violate normalization.

139. A ratebase offset of $344.026 million, applied in 2015 should be adopted.

140. TURN's proposed remedy to reduce SCE's state income tax by $2.090 million, less a $0.731 million increase in federal taxes per year during 2015-2017, is solely prospective.

141. TURN's proposal to reduce SCE's state income tax by $2.090 million, less a $0.731 million increase in federal taxes should be approved.

142. SCE should create a two-way Tax Accounting Memorandum Account to track all tax changes during this GRC period.

Section 23

143. A total M&S forecast of $116.948 million (nominal$) in 2015 should be approved.

144. A $103.360 million reduction to rate base relative to SCE's proposal for income tax lag should be approved.

145. SCE's proposals, including modifications proposed by TURN and uncontested by SCE, for other aspects of working cash lead lag study should be approved.

146. SCE's rate base should be offset by $180.269 million, or 90% of customer deposits.

147. SCE should be authorized to charge an offsetting interest expense based on the three-month commercial paper interest rate for the rate base offset of customer deposits.

148. The continued use of 10% of customer deposits for the community banking program, up to $20.030 million, should be approved.

149. SCE's uncontested proposed AFUDC rates should be approved.

Sections 25-28

150. SCE's forecast of OpX savings, as modified to provide 75 percent of forecast, adjusted savings for IT and customer service should be adopted.

151. SCE and CforAT's joint forecast of $1.5 million for accessibility issues should be approved.

152. SCE should be required to provide a more detailed forecast in its next GRC if it seeks to continue the accessibility program.

153. The settlement between SCE and JMP should be approved.

O R D E R

IT IS ORDERED that:

1. Application 13-11-003 is granted to the extent set forth in this Decision. Southern California Edison Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2015 test year base revenue requirement set forth in Appendix C, effective January 1, 2015.

2. Southern California Edison Company shall file its next General Rate Case for test year 2018 pursuant to the applicable Rate Case Plan adopted in Decision (D.) 89-01-040, as modified, including the requirements of D.14-12-025.

3. In its next General Rate Case (GRC), Southern California Edison Company (SCE) shall provide tables with at least five years of recorded spending information associated with each individual expense or expenditure forecast in excess of $1 million. SCE shall also provide summary tables, aggregating this information at the level of major categories (e.g. Transmission and Distribution Infrastructure Replacement, Human Resources). SCE shall provide its own comparable forecast and the Commission's adopted forecast from this GRC as a component of or accompaniment to these tables, both for individual forecasts and summary tables. SCE shall briefly explain any changes in scope of the forecasts, if they are not directly comparable. In the summary tables, SCE shall include any expenses or expenditures that were included in this GRC request, even if the individual expense or expenditure was not actually approved in this decision or implemented by SCE.

4. In its next general rate case, Southern California Edison Company shall provide an explanation of the workload analysis used to develop estimated labor increases.

5. Southern California Edison Company shall eliminate the following accounts:

a) Mohave Balancing Account;

b) Solar Photovoltaic Program Balancing Account;

c) Fuel Cell Program Memorandum Account;

d) Catastrophic Event Memorandum Account;

e) Market Redesign and Technology Upgrade Memorandum Account;

f) Edison SmartConnect Balancing Account;

g) Edison SmartConnect Opt-Out Memorandum Account; and

h) General Rate Case Revenue Requirement Memorandum Account.

6. Southern California Edison Company shall continue all accounts not eliminated or modified by this decision.

7. Southern California Edison Company (SCE) is authorized to institute a Safety and Reliability Investment Incentive Mechanism to replace the previous Reliability Investment Incentive Mechanism. SCE shall submit an advice letter on or before April 30, 2018 reporting on the results of its capital spending and staffing relative to the targets, and implementing any refunds, as described here. Specifically:

a. This mechanism will operate during this rate case period, 2015 through 2017.

b. The capital spending target is the sum of the authorized amounts in the core categories: Worst Circuit Rehabilitation, Underground Cable Life, Cable-in-Conduit Replacement, Underground Switch, Underground Structure Replacement, Circuit Breaker Replacements, and Substation Transformer Replacement.

c. The High Priority categories are: customer growth, storms, and claims.

d. If spending does not meet the capital spending target, overspending in the High Priority categories can offset underspending in the core categories if two conditions are true: the overspending in High Priority categories exceeds ten percent of the adopted forecast for those categories and Southern California Edison Company's actual rate of return on rate base for the period does not exceed the authorized rate of return. The first ten percent of overspending on High Priority categories cannot be used to offset underspending in the core categories under any circumstance. Otherwise, the difference between the capital spending target and the actual capital spending in the core categories shall be refunded to ratepayers.

e. The staffing target is 2,225 employees in the categories identified in exhibit SCE-3V1 at page 27. If Southern California Edison Company does not meet this target by the end of 2017, it shall refund $20,000 per employee for each of the first fifty employees it falls short of the target and $80,000 per employee beyond fifty. If a shortfall develops between September 31, 2017 and December 31, 2017, Southern California Edison Company may cure the shortfall by March 31, 2018 without penalty.

8. Southern California Edison Company is authorized to establish a Pole Loading Program Balancing Account. This account will record expenditures related to the Pole Loading Program and deteriorated pole replacements. The account will be capped at 15% above the adopted forecast amounts for 2016 and 2017. There will be no cap for 2015.

9. Southern California Edison Company (SCE) shall include in its direct showing in its next general rate case, the following:

a. SCE shall present a review of its efforts to ensure that SCE ratepayers are not unduly subsidizing other companies' use of joint use poles.

b. SCE shall present analysis of options to remediate additional overloaded poles beyond those replaced at SCE ratepayer expense. This analysis should address at least the following options: removing attachments, strengthening existing poles, or achieving greater cost share contributions from joint pole users.

c. SCE shall document its employee headcount forecast and show how that headcount forecast is applied in any cost forecast that relies on it.

d. SCE shall present a clear and coordinated showing on its recognition programs including Spot Bonuses and Awards to Celebrate Excellence.

e. SCE shall present a showing that the interim Emergency Operations Center remains used and useful.

f. SCE shall explicitly present its cost-benefit analysis of the General Office 2 Conference & Training Center.

g. If Energy Division has not published an affiliated transactions audit that includes a focused review of Non-Tariffed Products & Services by the end of 2015, SCE shall contract for an independent audit. SCE shall consult with Energy Division in hiring the auditor, developing the scope of work, and managing the audit. At a minimum, the audit shall review Non-Tariffed Products & Services incremental costs from 2012 to 2015. SCE shall include the results of this audit, and/or the review from Energy Division's affiliated transactions audit, in its next General Rate Case filing.

h. SCE shall present a net present value estimate of the impact of its changed formula to allocate tax expense, as measured from 2015, in its next General Rate Case filing. That estimate shall take into account the entire tax lives of the relevant depreciable assets.

i. SCE shall provide considerably more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense. At a minimum, this detail shall include:

   i. A quantitative discussion of the historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per-unit COR.

   ii. A quantitative discussion of the historical and anticipated future retirement mix (i.e., retirements among different asset

classes), identifying and explaining the key factors in changing or maintaining this mix.

iii. A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross-reference the proposal for life characteristics.

iv. An account-specific discussion of the process for allocating costs to COR.

j. If SCE wishes to continue the accessibility program and funding for the accessibility coordinator in the next General Rate Case period, it must provide a considerably more specific forecast and justification. In its direct showing, SCE shall include: a description of the accomplishments of the program up to that point, analysis of specific forecast costs, and demonstration that such costs are complementary and not duplicative of other forecasts.

10. Southern California Edison Company shall file a Tier 1 Advice Letter within twenty days of the effective date of this decision to implement the revenue requirement and ratemaking adopted herein. The revenue requirement and revised tariff sheets will be effective January 1, 2015. The balance of the General Rate Case Revenue Requirement Memorandum Account shall be amortized in rates from January 1, 2016 to December 31, 2017.

11. San Diego Gas & Electric Company's (SDG&E's) request for an authorized revenue requirement for Marine Mitigation is granted. SDG&E shall file a Tier 1 Advice Letter within twenty days of the effective date of this decision outlining its method to calculate its revenue requirement. SDG&E shall continue tracking its Marine Mitigation costs and revenue requirement differences in its Marine Mitigation Memorandum Account until the effective date of the rates adopted in its General Rate Case Application 14-11-003/4. SDG&E shall implement its marine mitigation revenue requirement and ratemaking adopted herein for marine mitigation concurrently with its General Rate Case. The marine

mitigation revenue requirement and revised tariff sheets, if any, will be effective January 1, 2015.

12. Within 45 days of the effective date of this decision, Southern California Edison Company shall issue a true-up of marine mitigation costs billed to San Diego Gas and Electric Company reflecting the categorization of costs as expense.

13. Southern California Edison Company shall transfer the General Rate Case Revenue Requirement Memorandum Account balance, as of the effective date of this decision, to its Authorized Base Revenue Requirement Balancing Account.

14. Southern California Edison Company and San Diego Gas & Electric Company are not permitted to recover any cost twice. If a cost permitted for recovery here is also recovered from the nuclear decommissioning trust (or any other source), Southern California Edison Company and/or San Diego Gas & Electric Company shall refund the revenue requirement associated with that cost to ratepayers, with interest.

15. Southern California Edison Company and San Diego Gas & Electric Company are authorized to file an application to recover costs in the event that California Coastal Commission does require additional reef construction, or other measures. In that application, Southern California Edison Company shall demonstrate that it has made a reasonable effort to represent ratepayers' interests in front of all applicable regulatory bodies and that its cost forecast is reasonable. Southern California Edison Company and San Diego Gas & Electric Company shall recover any such costs as operations and maintenance expense, not capital expenditures.

16. Southern California Edison Company is authorized to modify the Project Development Division Memorandum Account to record only non-labor expenses.

17. Southern California Edison Company should be authorized to transfer the final December 31, 2014 balance of Residential Service Disconnection Memorandum Account to Base Revenue Requirement Balancing Account for recovery in distribution rates as part of its advice letter filing implementing this decision.

18. Southern California Edison Company is authorized to extend the Residential Service Disconnection Memorandum Account through 2017.

19. Southern California Edison Company (SCE) is authorized to implement a Post-Test Year Ratemaking mechanism for both 2016 and 2017, as follows:

a. Expenses shall be escalated as proposed by SCE, using the same pricing methodology and pricing indices that we adopt for test year escalation, except for labor expenses [namely: disability programs, executive benefits, and 401(k)]. For labor expenses, SCE shall use Global Insight's most current forecast. For medical expenses, we adopt SCE's escalation rate of 8%. We also adopt SCE's proposed escalation rates for other benefits categories. For all other expenses, we adopt SCE's proposal of using the latest Global Insight escalation rates.

b. Capital-related revenues shall be escalated by increasing gross capital additions in the post test years at a rate of 2% per year above the 2015 authorized capital additions.

c. SCE's Z-factor recovery mechanism shall continue for 2016 and 2017.

d. We allow SCE to file an advice letter to implement the post-test year revenue requirement. SCE must file an advice letter by December 1st of 2015 and 2016. In these advice letters, SCE must update its post-test year revenue requirement for the following attrition year. For the second attrition year of 2017, SCE shall use the latest Global Insight escalation rates to escalate 2015 authorized level of expenses to 2016 and 2017 levels, but the 2016 authorized level of expenses will not be trued up to reflect the actual escalation factor for 2016.

20. Southern California Edison Company is authorized to create a two-way Tax Accounting Memorandum Account to track all tax changes during this GRC period.

21. The settlement between Southern California Edison Company and Joint Minority Parties is approved.

22. Application 13-11-003 is closed.

This order is effective today.

Dated _____, at Sacramento, California.

APPENDIX A

APPENDIX

List of Acronyms

ACRONYMS	MEANING
5YA	five-year average
A.	Application
AB	Assembly Bill
ACE	Awards to Celebrate Excellence
ADIT	Accumulated Deferred Income Taxes
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
APS	Arizona Public Service
ARIMA	Autoregressive Integrated Moving Average
ASD	Audit Services Department
ASLs	average service lives
ASR	Advanced Speech Recognition
BCD	Business Customer Division
BLT	Business License Tax
BRRBA	Base Revenue Requirement Balancing Account
C&C	Cybersecurity & Compliance Division
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CaL-SLA	California City-County Street Light Association
CANSPAM	Controlling the Assault of Non-Solicited Pornography and Marketing
CASL	Coalition for Affordable Streetlights
CCC	California Coastal Commission
CCEEB	California Council for Environmental and Economic Balance

CDP	Coastal Development permit
CEHS	Corporate Environmental, Health, and Safety
CEMA	Catastrophic Event Memorandum Account
CforAT	Center for Accessible Technology
CI	Conformance Index
CIAC	Contributions in Aid of Construction
CIC	Cable-in-Conduit
CIP	Critical Infrastructure Protection
CLRP	Circuit Load Reduction Program
CMS	Consolidated Mobile Solution
COR	Cost of Removal
CPI-U	Urban Consumer Price Index
CPUC	California Public Utilities Commission
CRAS	Centralized Remedial Action Scheme
CRE	Corporate Real Estate
CS&P	Client Services & Planning
CSA	Contract Services Agreement
CSRs	Customer Service Representatives
CUE	Coalition of Utility Employees
CWIP	Construction Work In Progress
D.	Decision
DESI	Distributed Energy Storage Integration
DFR/PMU	Digital Fault Recorded/Phasor Measurement Unit
DIMP	Distribution Inspection and Maintenance Program
DR	Demand Response
DSP	Distribution Substation Plan
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortization
EDEF	Equipment Demonstration and Evaluation Facility

eDMRM	Electronic Document Management/Records Management
EDS	Economic Development Services
EEI	Edison Electric Institute
EIC	Executive Incentive Compensation
EIX	Edison International
EOC	Emergency Operations Center
ERRA	Energy Resource Recovery Account
ESC	Edison SmartConnect®
ESCBA	Edison SmartConnect Balancing Account
ESOP	Employee Stock Ownership Plan
ESOPTMA	Employee Stock Ownership Plan Tax Memorandum Account
EVTC	Electric Vehicle Technical Center
FCC	Final Cost Centers
FCI	Facility Condition Index
FCPMA	Fuel Cell Program Memorandum Account
FERC	Federal Energy Regulatory Commission
FFH	Factory Fired Hours
FL&OS	Financial, Legal, and Operational Services
FTE	Full Time Equivalent
GCC	Grid Control Center
GMS	Generation Management System
GO	General Order
GO2	General Order 2
GRC	General Rate Case
GRSM	Gross Revenue Sharing Mechanism
HAN	Home Area Network
HGPI	Hot Gas Path Inspection
HR	Human Resources

IBC	Irwindale Business Center
IP&EA	Integrated Planning & Environmental Affairs
IT	Information Technology
ITS	Infrastructure Technology Services
JMP	Joint Minority Parties
JPO	Joint Pole Organization
kV	kilovolt
kW	kilowatt
LED	Light Emitting Diode
LPA	Local Public Affairs
LRY	last recorded year
LTI	Long Term Incentives
LTIP	Long-Term Incentive Plan
M&S	Materials and Supplies
MAP	Master Access Project
MIP	Management Incentive Program
MRTUMA	Market Redesign and Technology Upgrade Memorandum Account
MSO	Meter Services Organization
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOEIP	Non-Officer Executive Incentive Compensation Program
NSR	Net Salvage Ratio
NTP&S	Non-Tariffed Products and Services
O&M	Operations and Maintenance
OBs	Opening Briefs
ODI	Overhead Detail Inspection
OIR	Order Instituting Rulemaking
OOR	Other Operating Revenue

OpX	Operational Excellence
ORA	Office of Ratepayer Advocates
OS	Operational Services
OU	Operating Unit
P&PR	Planning & Performance Reporting
PB Project	Pebbly Beach Generating Station Generation Automation Project
PBOPs	Post-retirement Benefits Other than Pensions
PCAN	A type of agricultural meter
PCB	Polychlorinated Biphenyl
PDD	Project Development Division
PDDMA	Project Development Division Memorandum Account
PDL	Polynomial Distributed Lag
PG&E	Pacific Gas and Electric Company
PLP	Pole Loading Program
PLPBA	PLP Balancing Account
PMO	Program Management Organization
PPA	Power Purchase Agreement
PPO	Planning and Performance Organization
psf	Pounds per square foot
PTYR	Post-Test Year Ratemaking
PVNGS	Palo Verde Nuclear Generating Station
R	Rulemaking
RAS	Remedial Action Schemes
RCMS	Renewable Contract Management System
REI	Retirement Experience Index
RIIM	Reliability Investment Incentive Mechanism
RO	Results of Operations
RP&A	Regulatory Operations and Regulatory Policy & Affairs

RS	Results Sharing
RSDMA	Residential Service Disconnection Memorandum Account
RTEM	Real Time Energy Meters
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	Software Asset Management
SBUA	Small Business Utility Advocates
SCE	Southern California Edison Company
SCJPC	Southern California Joint Pole Committee
SDD	Supplier Diversity and Development Department
SDG&E	San Diego Gas & Electric Company
SERP	Substation Equipment Replacement Program
SIR	Substation Infrastructure Replacement
SM&P	Service Management & Planning
SoCalGas	Southern California Gas Company
PV	Photovoltaic
SOMA	SmartConnect Opt-Out Memorandum Account
SONGS	San Onofre Nuclear Generating Station
SPR	Simulated Plant Record
SPS	Southwestern Public Service Company
SPVP	Solar Photovoltaic Program
SPVPBA	Solar Photovoltaic Program Balancing Account
SRIIM	Safety and Reliability Investment Incentive Mechanism
SS&C	The Safety, Security, and Compliance
SSID	Shop Services and Instrumentation Division
STIP	Short-Term Incentive Program
T&D	Transmission and Distribution
TBCLE	Testing-Based Cable Life Extension

TCPA	Telephone Consumer Protection Act
TCS	Total Compensation Study
TDM	Technology Delivery and Maintenance
TSD	Transportation Services Department
TURN	The Utility Reform Network
TY	Test Year
UDI	Underground Detailed Inspections
VAR	Volt-Ampere Reactive
WCR	Worst Circuit Rehabilitation
WECC	Western Electricity Coordinating Council
WPI-IND	All Manufacturing Commodity Index
WMDVE	Women, Minority, and Disabled Veteran Enterprise

(END OF APPENDIX A)

APPENDIX B

Timeline of Events Relevant to Disputed Tax Issues

Date	Event	Citation
November 23, 2010	Application A.10-11-015	D.12-11-051
March 1, 2011	Scoping Ruling	D.12-11-051
August 19, 2011	Rev. Proc. 2011-43 published	Exh. SCE-26 at 39.
July 25-26 and August 8-26, 2011	Evidentiary hearings	D.12-11-051
September 26, 2011	Opening briefs due	D.12-11-051
October 17, 2011	Reply briefs due	D.12-11-051
October 24, 2011	Update Testimony	D.12-11-051
November 3, 2011	Update hearing	D.12-11-051
November 15, 2011	Update OBs due	D.12-11-051
November 25, 2011	LB&I Directive published	Exh. SCE-26 at 39.
November 27, 2011	Update reply briefs due	D.12-11-051
February, 2012	2011 SCE Form 10-K	Exh. TURN-05 at 102.
February, 2012	2011 SCE Annual Report	Exh. TURN-05 at 101, fn. 188
August 2012	SCE files 2011 tax return	SCE-26V2 at 42
August 24, 2012	Form 3115/Repair Deduction Election filed with IRS	Exh. TURN-05 at 102.
September 24, 2012	Ex parte communication between SCE and Commission staff	[Docket]
October 19, 2012	Proposed Decision	D.12-11-051
November 8, 2012	SCE Motion to File Comments on Results of Operations Model	[Docket]
November 8, 2012	Comments on PD due	D.12-11-051
November 13, 2012	Reply Comments on PD due	D.12-11-051
November 13-15, 2012	Ex parte communications between SCE and Commission staff	[Docket]
November 16, 2012	Oral argument	[Docket]
November 27, 2012	Ex parte communication between SCE and Commission staff	[Docket]
November 29, 2012	D.12-11-051 closes proceeding	D.12-11-051
February, 2013	EIX 2012 Annual Report	Exh. TURN-05 at 102.

(End of Appendix B)

APPENDIX C

~~Results of Operations 2015~~RESULTS OF OPERATIONS 2015

Southern California Edison
2015 General Rate Case
Application
Results of Operations Model
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APPENDIX C
Southern California Edison Company
2015 Results of Operations
Thousands of Dollars

Line No.	Item	Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	Adopted CPUC Total	SCE Request (Based on May 2015 Update Testimony)	Difference (Adopted Less SCE Request)
1.	**TOTAL OPERATING REVENUES**	5,156,393	64,500	(248)	(38,349)	5,182,297	5,511,779	(329,483)
2.	**OPERATING EXPENSES:**							
3.	Production							
4.	Steam	9,362				9,362	7,342	2,021
5.	Nuclear	73,695				73,695	73,818	(123)
6.	Hydro	52,850				52,850	53,142	(292)
7.	Other	116,944				116,944	120,835	(3,891)
8.	Subtotal Production	252,851	-	-	-	252,851	255,137	(2,285)
9.	Transmission	91,389				91,389	93,402	(2,013)
10.	Distribution	514,783				514,783	545,469	(30,685)
11.	Customer Accounts	168,209				168,209	174,719	(6,510)
12.	Uncollectibles	12,272	131	(1)	(91)	12,311	13,095	(784)
13.	Customer Service & Information	37,948				37,948	39,020	(1,072)
14.	Administrative & General	757,814				757,814	819,258	(61,444)
15.	Franchise Requirements	46,897	584	(2)	(349)	47,131	50,128	(2,997)
16.	Revenue Credits	(147,491)				(147,491)	(147,470)	(22)
17.	Subtotal	1,734,672	715	(3)	(440)	1,734,945	1,842,758	(107,813)
18.	Escalation	101,951	-	-	-	101,951	109,339	(7,389)
19.	Depreciation	1,483,189	49,100	-	-	1,532,289	1,676,696	(144,407)
20.	Taxes Other Than On Income	245,667				245,667	252,343	(6,677)
21.	Taxes Based On Income	204,289	5,170	(100)	(12,339)	197,020	197,020	1
22.	Total Taxes	449,956	5,170	(100)	(12,339)	442,687	449,363	(6,676)
23.	**TOTAL OPERATING EXPENSES**	3,769,768	54,985	(103)	(12,779)	3,811,871	4,078,156	(266,284)
24.	**NET OPERATING REVENUE**	1,386,625	9,514	(145)	(25,569)	1,370,425	1,433,624	(63,198)
25.	**RATE BASE**	17,552,216	147,280	1,837	(323,662)	17,375,834	18,175,824	(799,990)
26.	**RATE OF RETURN**	7.90%	6.46%	-7.90%	-7.90%	7.89%	7.89%	7.90%
27.	**REVENUES AT PRESENT RATES**	5,632,680				5,632,680	5,632,680	-
28.	**INCREASE OVER PRESENT REVENUE REQUIREMENT IN RATES**	(476,287)				(450,383)	(120,901)	(329,483)
29.	**RSDMA Undercollection**	17,981				17,981	17,981	-
30.	**NET INCREASE OVER PRESENT RATES**	(458,305)				(432,402)	(102,919)	(329,483)
	Decrease over present revenue requirement in rates					-8.00%		
	Net Decrese over present rates					-7.68%		

APPENDIX C

Southern California Edison Company
2015 Total Company Results of Operation
Thousands of Dollars

Line No.	Item	Adopted
1.	**TOTAL OPERATING REVENUES**	6,153,926
2.	**OPERATING EXPENSES:**	
3.	Production	
4.	Steam	9,362
5.	Nuclear	73,695
6.	Hydro	52,850
7.	Other	116,944
8.	Subtotal Production	252,851
9.	Transmission	172,600
10.	Distribution	519,191
11.	Customer Accounts	168,209
12.	Uncollectibles	14,646
13.	Customer Service & Information	37,948
14.	Administrative & General	805,493
15.	Franchise Requirements	55,970
16.	Revenue Credits	(193,280)
17.	Subtotal	1,833,628
18.	Escalation	108,225
19.	Depreciation	1,705,441
20.	Taxes Other Than On Income	304,352
21.	Taxes Based On Income	403,650
22.	Total Taxes	708,002
23.	**TOTAL OPERATING EXPENSES**	4,355,296
24.	**NET OPERATING REVENUE**	1,798,630
25.	**RATE BASE**	22,767,473
26.	**RATE OF RETURN**	7.90%

APPENDIX C				
Southern California Edison				
2015 Results of Operations				
Sales Forecast				
				Adopted
Sales Forecast (GWh)				
	Residential			29,493
	Commercial			41,718
	Industrial			8,135
	Other Public Authority 1/			4,675
	Agricultural			1,428
				85,449
Customer Forecast (No. of Customers)				
	Residential			4,393.2
	Commercial			564.4
	Industrial			10.3
	Other Public Authority 1/			46.2
	Agricultural			21.7
				5,035.9
1/	Includes Streetlighting class.			

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Total Production

Line No.	Account No.	Description	CPUC Adopted
1.		TOTAL STEAM	9,362
2.		TOTAL NUCLEAR	73,695
3.		TOTAL HYDRO	52,850
4.		TOTAL OTHER	116,944
5.		TOTAL PRODUCTION Constant 2012$	252,851
6.		Escalation	13,439
7.		TOTAL INCLUDING ESCALATION (2015$)	266,290
8.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
9.		Total Company Constant 2012$	
10.		Labor	92,207
11.		Non-Labor	133,709
12.		Other	26,935
13.		Subtotal Total Company	252,851
14.		Escalation:	
15.		Labor	7,243
16.		Non-Labor	6,196
17.		Other	-
18.		Subtotal Total Company	13,439
19.		TOTAL INCLUDING ESCALATION (2015$)	266,290

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Steam Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	500	Operation Supervision and Engineering	9,054
3.	501	Fuel	-
4.	502	Steam Expenses	-
5.	505	Electric Expenses	-
6.	506	Miscellaneous Steam Power Expenses	180
7.	507	Rents	-
8.	509	Allowances	-
		TOTAL OPERATION	9,234
9.		Maintenance	
10.	510	Maintenance Supervision and Engineering	-
11.	511	Maintenance of Structures	-
12.	512	Maintenance of Boiler Plant	-
13.	513	Maintenance of Electric Plant	-
14.	514	Maintenance of Miscellaneous Steam Plant	128
15.		TOTAL MAINTENANCE	128
16.		TOTAL STEAM Constant 2012$	9,362
17.		Escalation	731
18.		TOTAL STEAM INCLUDING ESCALATION (2015$)	10,094
19.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
20.		Total Steam Constant 2012$	
21.		Labor	9,255
22.		Non-Labor	107
23.		Other	-
24.		Subtotal Total Steam	9,362
25.		Escalation:	
26.		Labor	727
27.		Non-Labor	4
28.		Other	-
29.		Subtotal Total Steam	731
30.		TOTAL STEAM INCLUDING ESCALATION (2015$)	10,094

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Nuclear Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	517	Operation Supervision and Engineering	-
3.	518	Nuclear Fuel Expense	-
4.	519	Coolants and Water	-
5.	520	Steam Expenses	-
6.	523	Electric Expenses	-
7.	524	Miscellaneous Nuclear Power Expenses	73,695
8.	525	Rents	-
9.		TOTAL OPERATION	73,695
10.		Maintenance	
11.	528	Maintenance Supervision and Engineering	-
12.	529	Maintenance of Structures	-
13.	530	Maintenance of Reactor Plant Equipment	-
14.	531	Maintenance of Electric Plant	-
15.	532	Maintenance of Miscellaneous Nuclear Plant	-
16.		SONGS 2&3 Refueling Outage Adjustment	-
17.		TOTAL MAINTENANCE	-
18.		TOTAL NUCLEAR Constant 2012$	73,695
19.		Escalation	4,103
20.		TOTAL NUCLEAR INCLUDING ESCALATION (2015$)	77,798
21.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
22.		Total Nuclear Constant 2012$	
23.		Labor	173
24.		Non-Labor	73,522
25.		Other	-
26.		Subtotal Total Nuclear	73,695
27.		Escalation:	
28.		Labor	14
29.		Non-Labor	4,089
30.		Other	-
31.		Subtotal Total Nuclear	4,103
32.		TOTAL NUCLEAR INCLUDING ESCALATION (2015$)	77,798

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Hydro Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	535	Operation Supervision and Engineering	-
3.	536	Water for Power	5,640
4.	537	Hydraulic Expenses	-
5.	538	Electric Expenses	-
6.	539	Miscellaneous Hydraulic Power Generation Expenses	31,160
7.	540	Rents	-
8.		TOTAL OPERATION	36,800
9.		Maintenance	
10.	541	Maintenance Supervision and Engineering	-
11.	542	Maintenance of Structures	-
12.	543	Maintenance of Reservoirs, Dams and Waterways	-
13.	544	Maintenance of Electric Plant	-
14.	545	Maintenance of Miscellaneous Hydraulic Plant	16,050
15.		TOTAL MAINTENANCE	16,050
16.		TOTAL HYDRO Constant 2012$	52,850
17.		Escalation	2,951
18.		TOTAL HYDRO INCLUDING ESCALATION 2015$	55,801
19.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
20.		Total Hydro Constant 2012$	
21.		Labor	28,506
22.		Non-Labor	24,344
23.		Other	-
24.		Subtotal Total Hydro	52,850
25.		Escalation:	
26.		Labor	2,239
27.		Non-Labor	712
28.		Other	-
29.		Subtotal Total Hydro	2,951
30.		TOTAL HYDRO INCLUDING ESCALATION 2015$	55,801

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Other Production

Line No.	Account No.	Description	CPUC Adopted
1.		Operation	
2.	546	Operation Supervision and Engineering	-
3.	547	Fuel	-
4.	548	Generation Expenses	-
5.	549	Miscellaneous Other Power Generation Expenses	24,821
6.	550	Rents	2,084
7.		TOTAL OPERATION	26,905
8.		Maintenance	
9.	551	Maintenance Supervision and Engineering	-
10.	552	Maintenance of Structures	-
11.	553	Maintenance of Generating and Electric Plant	-
12.	554	Maintenance of Miscellaneous Other Power Generation Plant	43,949
13.	555	Purchased Power	-
14.	556	System Control and Load Dispatching	-
15.	557	Other Expenses	46,090
16.		TOTAL MAINTENANCE	90,039
17.		TOTAL OTHER Constant 2012$	116,944
18.		Escalation	5,654
19.		TOTAL OTHER INCLUDING ESCALATION (2015$)	122,598
20.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
21.		Total Other Constant 2012$	
22.		Labor	54,273
23.		Non-Labor	35,736
24.		Other	26,935
25.		Subtotal Total Other	116,944
26.		Escalation:	
27.		Labor	4,263
28.		Non-Labor	1,391
29.		Other	-
30.		Subtotal Total Other	5,654
31.		TOTAL OTHER INCLUDING ESCALATION (2015$)	122,598

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Transmission Expenses

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	560	Operation Supervision and Engineering	17,461
3.	561	Load Dispatching	4,677
4.	562	Station Expenses	10,563
5.	563	Overhead Line Expenses	-
6.	564	Underground Line Expenses	-
7.	565	Transmission of Electricity by Others	-
8.	566	Miscellaneous Transmission Expenses	28,304
9.	567	Rents	-
10.		TOTAL OPERATION	61,005
11.		Maintenance:	
12.	568	Maintenance Supervision and Engineering	7,625
13.	569	Maintenance of Structures	-
14.	570	Maintenance of Station Equipment	5,298
15.	571	Maintenance of Overhead Lines	16,439
16.	572	Maintenance of Underground Lines	-
17.	573	Maintenance of Miscellaneous Transmission Plant	1,021
18.		TOTAL MAINTENANCE	30,383
19.		TOTAL TRANSMISSION EXPENSE Constant 2012$	91,388
20.		Escalation	4,329
21.		TOTAL INCLUDING ESCALATION (2015$)	95,717
22.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
23.		Total Constant 2012$	
24.		Labor	41,878
25.		Non-Labor	41,382
26.		Other	8,129
27.		Subtotal	91,390
28.		Escalation:	
29.		Labor	3,397
30.		Non-Labor	932
31.		Other	-
32.		Subtotal	4,329
33.		TOTAL INCLUDING ESCALATION (2015$)	95,719

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Distribution Expenses

Line No.	Account No.	Description	CPUC Adopted
1.		Operation:	
2.	580	Operation Supervision and Engineering	35,196
3.	582	Station Expenses	28,416
4.	583	Overhead Line Expenses	83,445
5.	584	Underground Line Expenses	-
6.	585	Street Lighting and Signal System Expenses	8,689
7.	586	Meter Expenses	29,303
8.	587	Customer Installations Expenses	7,879
9.	588	Miscellaneous Distribution Expenses	107,421
10.	589	Rents	-
11.		TOTAL OPERATION	300,349
12.		Maintenance:	
13.	590	Maintenance Supervision and Engineering	(3,141)
14.	591	Maintenance of Structures	-
15.	592	Maintenance of Station Equipment	13,560
16.	593	Maintenance of Overhead Lines	144,083
17.	594	Maintenance of Underground Lines	42,533
18.	595	Maintenance of Line Transformers	-
19.	596	Maintenance of Street Lighting and Signal Systems	-
20.	597	Maintenance of Meters	-
21.	598	Maintenance of Miscellaneous Distribution Plant	17,402
22.		TOTAL MAINTENANCE	214,437
23.		TOTAL DISTRIBUTION EXPENSE Constant 2012$	514,786
24.		Escalation	28,798
25.		TOTAL INCLUDING ESCALATION (2015$)	543,584
26.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
27.		Total Constant 2012$	
28.		Labor	263,503
29.		Non-Labor	249,354
30.		Other	1,926
31.		Subtotal	514,783
32.		Escalation:	
33.		Labor	20,698
34.		Non-Labor	8,101
35.		Other	-
36.		Subtotal	28,798
37.		TOTAL INCLUDING ESCALATION (2015$)	543,581

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Accounts Expenses

Line No.	Account No.	Description	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
1.	901	Supervision	8,078				8,078
2.	902	Meter Reading Expenses	16,771				16,771
3.	903	Customer Records and Collection Expenses	105,329				105,329
4.	904	Uncollectible Accounts	12,272	131	(1)	(91)	12,311
5.	905	Miscellaneous Customer Accounts Expenses	37,814				37,814
6.		Interest Offset on Customer Deposits	216				216
7.		TOTAL CUSTOMER ACCOUNTS Constant 2012$	180,480				180,519
8.		Escalation	13,001				13,001
9.		TOTAL INCLUDING ESCALATION (2015$)	193,481				193,520
10.		Less: Account 904 (Uncollectible Accounts)	(12,272)				(12,311)
11.		TOTAL LESS ACCOUNT 904 (2015$)	181,209				181,209
12.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:					
13.		Total Constant 2012$					
14.		Labor	106,957				106,957
15.		Non-Labor	60,424				60,424
16.		Other	13,100	131	(1)	(91)	13,138
17.		Subtotal	180,481				180,519
18.		Escalation:					
19.		Labor	8,401				8,401
20.		Non-Labor	4,600				4,600
21.		Other	-				-
22.		Subtotal	13,001				13,001
23.		TOTAL INCLUDING ESCALATION (2015$)	193,482				193,520
24.		Less: Account 904 (Uncollectible Accounts)	(12,278)				(12,311)
25.		TOTAL LESS ACCOUNT 904 (2015$)	181,204				181,209

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Customer Service And Information And Sales Expenses

Line No.	Account No.	Description	CPUC Adopted
1.	907	Supervision	12,414
2.	908	Customer Assistance Expenses	25,534
3.	909	Informational and Instructional Advertising Expenses	-
4.	910	Miscellaneous Customer Service and Informational Expenses	-
5.	912	Demonstrating and Selling Expenses	-
6.	913	Advertising Expenses	-
7.		TOTAL CUSTOMER SERVICE & INFORMATION	37,948
8.	916	Miscellaneous Sales Expenses	-
9.		TOTAL SALES EXPENSE	-
10.		TOTAL CSI AND SALES EXPENSE Constant 2012$	37,948
11.		Escalation	2,547
12.		TOTAL INCLUDING ESCALATION (2015$)	40,495
13.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:	
14.		Total Constant 2012$	
15.		Labor	24,849
16.		Non-Labor	13,099
17.		Other	-
18.		Subtotal	37,948
19.		Escalation:	
20.		Labor	1,952
21.		Non-Labor	595
22.		Other	-
23.		Subtotal	2,547
24.		TOTAL INCLUDING ESCALATION (2015$)	40,495

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
Thousands of Dollars
Category: Administrative And General Expenses

Line No.	Account No.	Description	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
1.		Operation:					
2.	920	Administrative and General Salaries/Office Supplies and Expenses	288,978				288,978
3.	921	Administrative and General Salaries/Office Supplies and Expenses	177,128				177,128
4.	922	Administrative Expenses Transferred - Credit	(112,379)				(112,379)
5.	923	Outside Services Employed	49,326				49,326
6.	924	Property Insurance	17,850				17,850
7.	925	Injuries and Damages	107,430				107,430
8.	926	Employee Pensions and Benefits	184,792				184,792
9.	927	Franchise Requirements	46,897	584	(2)	(349)	47,131
10.	928	Regulatory Commission Expenses	-				-
11.	930	General Advertising Expenses-Miscellaneous General Expenses	19,812				19,812
12.	931	Rents	14,322				14,322
13.		Reduction for Productivity Savings/A&G Credit for Catalina Utilities	(640)				(640)
14.		TOTAL OPERATION	793,516				793,749
15.		Maintenance:					
16.	935	Maintenance of General Plant	11,196				11,196
17.		TOTAL MAINTENANCE	11,196				11,196
18.		TOTAL A&G Constant 2012$	804,711				804,945
19.		Escalation	39,839				39,839
20.		TOTAL INCLUDING ESCALATION (2015$) 1/	844,551				844,784
21.		Less: Account 927 (Franchise Requirements)	(46,897)				(47,131)
22.		TOTAL LESS ACCOUNT 927 (2015$)	797,654				797,653
23.		LABOR, NON-LABOR AND OTHER EXPENSE DETAIL:					
24.		Total Constant 2012$					
25.		Labor	302,247				302,247
26.		Non-Labor	292,694				292,694
27.		Other	209,770	584	(2)	(349)	210,003
28.		Subtotal	804,711				804,944
29.		Escalation:					
30.		Labor	24,176				24,176
31.		Non-Labor	15,663				15,663
32.		Other	-				-
33.		Subtotal	39,839				39,839
34.		TOTAL INCLUDING ESCALATION (2015$) 1/	844,550				844,784
35.		Less: Account 927 (Franchise Requirements)	(46,897)				(47,131)
36.		TOTAL LESS ACCOUNT 927 (2015$)	797,653				797,653

1/ Escalation for pensions & benefits is included in this amount

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
	NON-ESCALATED					
1.	Production					
2.	Steam	9,362				9,362
3.	Nuclear	73,695				73,695
4.	Hydro	52,850				52,850
5.	Other	116,944				116,944
6.	Subtotal - Production	252,851				252,851
7.	Transmission	91,389				91,389
8.	Distribution	514,784				514,784
9.	Customer Accounts	168,209				168,209
10.	Uncollectibles (Account 904)	12,272	131	(1)	(91)	12,311
11.	Customer Service and Informational and Sales	37,948				37,948
12.	Administrative and General	757,814				757,814
13.	Franchise Requirements (Account 927)	46,897	584	(2)	(349)	47,131
14.	TOTAL O&M EXPENSE Constant 2012$	1,882,164				1,882,437
	ESCALATED					
15.	Production					
16.	Steam	10,093				10,093
17.	Nuclear	77,798				77,798
18.	Hydro	55,801				55,801
19.	Other	122,598				122,598
20.	Subtotal - Production	266,290				266,290
21.	Transmission	95,717				95,717
22.	Distribution	543,582				543,582
23.	Customer Accounts	181,210				181,210
24.	Uncollectibles (Account 904)	12,278	131	(1)	(91)	12,317
25.	Customer Service and Informational and Sales	40,495				40,495
26.	Administrative and General	797,654				797,654
27.	Franchise Requirements (Account 927)	46,935	584	(2)	(349)	47,168
28.	TOTAL O&M EXPENSE 2015$	1,984,161				1,984,434
	ESCALATION					
29.	Production					
30.	Steam	731				731
31.	Nuclear	4,103				4,103
32.	Hydro	2,951				2,951
33.	Other	5,654				5,654
34.	Subtotal - Production	13,439				13,439
35.	Transmission	4,328				4,328
36.	Distribution	28,798				28,798
37.	Customer Accounts	13,002				13,001
38.	Uncollectibles (Account 904)	0				6
39.	Customer Service and Informational and Sales	2,547				2,547
40.	Administrative and General	39,839				39,840
41.	Franchise Requirements (Account 927)	-				38
42.	TOTAL ESCALATION	101,953				101,997

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Labor Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	9,255
3.	Nuclear	173
4.	Hydro	28,506
5.	Other	54,273
6.	Subtotal - Production	92,207
7.	Transmission	41,878
8.	Distribution	263,503
9.	Customer Accounts	106,957
10.	Uncollectibles (Account 904)	0
11.	Customer Service and Informational and Sales	24,849
12.	Administrative and General	302,248
13.	Franchise Requirements (Account 927)	0
14.	TOTAL O&M EXPENSE Constant 2012$	831,642
	ESCALATED	
15.	Production	
16.	Steam	9,982
17.	Nuclear	187
18.	Hydro	30,745
19.	Other	58,536
20.	Subtotal - Production	99,450
21.	Transmission	45,275
22.	Distribution	284,201
23.	Customer Accounts	115,358
24.	Uncollectibles (Account 904)	-
25.	Customer Service and Informational and Sales	26,801
26.	Administrative and General	326,424
27.	Franchise Requirements (Account 927)	-
28.	TOTAL O&M EXPENSE 2015$	897,509
	ESCALATION	
29.	Production	
30.	Steam	727
31.	Nuclear	14
32.	Hydro	2,239
33.	Other	4,263
34.	Subtotal - Production	7,243
35.	Transmission	3,397
36.	Distribution	20,698
37.	Customer Accounts	8,401
38.	Uncollectibles (Account 904)	-
39.	Customer Service and Informational and Sales	1,952
40.	Administrative and General	24,176
41.	Franchise Requirements (Account 927)	-
42.	TOTAL ESCALATION	65,867

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Non Labor Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted
	NON-ESCALATED	
1.	Production	
2.	Steam	107
3.	Nuclear	73,522
4.	Hydro	24,344
5.	Other	35,736
6.	Subtotal - Production	133,709
7.	Transmission	41,382
8.	Distribution	249,354
9.	Customer Accounts	60,424
10.	Uncollectibles (Account 904)	-
11.	Customer Service and Informational and Sales	13,099
12.	Administrative and General	292,694
13.	Franchise Requirements (Account 927)	-
14.	TOTAL O&M EXPENSE Constant 2012$	790,662
	ESCALATED	
15.	Production	
16.	Steam	111
17.	Nuclear	77,611
18.	Hydro	25,056
19.	Other	37,127
20.	Subtotal - Production	139,905
21.	Transmission	42,314
22.	Distribution	257,455
23.	Customer Accounts	65,024
24.	Uncollectibles (Account 904)	-
25.	Customer Service and Informational and Sales	13,694
26.	Administrative and General	308,357
27.	Franchise Requirements (Account 927)	-
28.	TOTAL O&M EXPENSE 2015$	826,749
	ESCALATION	
29.	Production	
30.	Steam	4
31.	Nuclear	4,089
32.	Hydro	712
33.	Other	1,391
34.	Subtotal - Production	6,196
35.	Transmission	932
36.	Distribution	8,101
37.	Customer Accounts	4,600
38.	Uncollectibles (Account 904)	-
39.	Customer Service and Informational and Sales	595
40.	Administrative and General	15,663
41.	Franchise Requirements (Account 927)	-
42.	TOTAL ESCALATION	36,086

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Other Expenses
($000)
Category: Total O&M Expenses

Line No.	Description	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
	NON-ESCALATED					
1.	Production					
2.	Steam	0				-
3.	Nuclear	-				-
4.	Hydro	-				-
5.	Other	26,935				26,935
6.	Subtotal - Production	26,935				26,935
7.	Transmission	8,128				8,128
8.	Distribution	1,927				1,927
9.	Customer Accounts	828				828
10.	Uncollectibles (Account 904)	12,272	131	(1)	(91)	12,311
11.	Customer Service and Informational and Sales	-				-
12.	Administrative and General	162,873				162,873
13.	Franchise Requirements (Account 927)	46,897	584	(2)	(349)	47,131
14.	TOTAL O&M EXPENSE Constant 2012$	259,860				260,132
	ESCALATED					
15.	Production					
16.	Steam	0				-
17.	Nuclear	-				-
18.	Hydro	-				-
19.	Other	26,935				26,935
20.	Subtotal - Production	26,935				26,935
21.	Transmission	8,128				8,128
22.	Distribution	1,927				1,927
23.	Customer Accounts	828				828
24.	Uncollectibles (Account 904)	12,278	131	(1)	(1)	12,408
25.	Customer Service and Informational and Sales	-				-
26.	Administrative and General	162,873				162,873
27.	Franchise Requirements (Account 927)	46,935	584	(2)	(2)	47,515
28.	TOTAL O&M EXPENSE 2015$	259,904				260,614
	ESCALATION					
29.	Production					
30.	Steam	-				-
31.	Nuclear	-				-
32.	Hydro	-				-
33.	Other	-				-
34.	Subtotal - Production	-				-
35.	Transmission	-				-
36.	Distribution	-				-
37.	Customer Accounts	-				-
38.	Uncollectibles (Account 904)	-				97
39.	Customer Service and Informational and Sales	-				-
40.	Administrative and General	-				-
41.	Franchise Requirements (Account 927)	-				385
42.	TOTAL ESCALATION	-				481

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Taxes - Other
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted
1.	**Ad Valorem Taxes**	184,571
2.	**Payroll Taxes**	
3.	Federal Insurance Contribution Act (FICA)	54,866
4.	Federal Unemployment Tax Act	290
5.	State Unemployment Tax Act	1,978
6.	Total Payroll Taxes	57,133
7.	Misc. Taxes	4,614
8.	ITC Amortization on CTC Property	(651)
9.	ARAM Expense on CTC Property	0
10.	Total Taxes Other Than Income	245,667

Taxes - Income

Thousands of Dollars

Line No.	Description	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
1.	**California Corporation Franchise Tax**					
2.	Operating Revenues	5,156,393				5,156,393
3.	Operating Expenses	1,836,638				1,836,638
4.	Taxes Other Than Income	245,667				245,667
5.	Subtotal Expenses	2,082,305				2,082,305
6.	Income Tax Adjustments (Sch M)	1,538,091				1,538,091
7.	California Taxable Income	1,535,998				1,535,998
8.	CCFT Tax Rate	8.840%				0
9.	California Corp Franchise Tax	34,964				34,964
10.	Arizona Income Tax Rate	0.0270%				0.0270%
11.	New Mexico Income Tax Rate	0.0000%				0.0000%
12.	Arizona Income Tax	107				107
13.	New Mexico Income Tax	0				0
14.	Total Other State Income Taxes	107				107
15.	Total State Income Taxes	35,071				35,071
16.	**Federal Income Tax**					
17.	Operating Revenues	5,156,393				5,156,393
18.	Operating Expenses	1,836,638				1,836,638
19.	Taxes Other Than Income	245,667				245,667
20.	Total State Income Taxes	35,071				35,071
21.	Less: Current Year's CCFT	34,964				34,964
22.	Plus: Prior Year's CCFT	41,295				41,295
23.	Subtotal Expenses	2,123,706				2,123,706
24.	Income Tax Adjustments (Sch M)	1,545,716				1,545,716
25.	Federal Taxable Income	1,486,971				1,486,971
26.	FIT Rate	35.000%				0
27.	Federal Income Tax	121,273				121,273
28.	Taxes Deferred (Plant)	35,498				35,498
29.	Taxes Deferred (AFUDC Debt)	4,239				4,239
30.	Taxes Deferred (Cap. Int.)	13,329				13,329
31.	Contributions in Aid of Construction	(4,284)				(4,284)
32.	Investment Tax Credit	(4,876)				(4,876)
33.	Accrued Vacation Pay	158				158
34.	Total Federal Income Taxes	165,335				165,335
35.	Total Taxes-Income (State and Fed)	200,406				200,406

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Depreciation and Amortization Expense
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted	Legacy Meters	Mohave Credit	CPUC Total
1	DEPRECIATION				
2	Generation				
3	Nuclear				
4	San Onofre	0			0
5	Palo Verde	12,269			12,269
6	Other Production	29,963			29,963
7	Coal	25,829			25,829
8	Hydro	32,848			32,848
9	Mountainview	20,172			20,172
10	Total Generation	121,081			121,081
11	Transmission				
12	Land	921			921
13	Substations	58,640			58,640
14	Lines	38,185			38,185
15	Total Transmission	97,746			97,746
16	Distribution				
17	Land	1,137	65		1,202
18	Substations	82,888	4,923		87,811
19	Lines	672,831	44,112		716,943
20	Total Distribution	756,856			805,956
21	General	228,680			228,680
22	TOTAL DEPRECIATION	1,204,363			1,253,463
23	AMORTIZATION				
24	Radio Frequency	440			440
25	Hydro Relicensing	3,773			3,773
26	Miscellaneous Intangibles	24			24
27	Capitalized Software	274,587			274,587
28	TOTAL AMORTIZATION	278,824			278,824
29	TOTAL DEPRECIATION AND AMORTIZATION	1,483,187			1,532,287

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Summary of Electric Rate Base
Thousands of Dollars

Line No.	Item	CPUC Adopted	Legacy Meters	Mohave Credit	Rate Base Adjustment	CPUC Total
1	**FIXED CAPITAL**					
2	Plant in Service	30,896,161				30,896,161
3	Capitalized Software	1,556,232				1,556,232
4	Other Intangibles	168,512				168,512
5	Subtotal Plant in Service	32,620,905				32,620,905
6	**ADJUSTMENTS**					
7	Customer Advances for Construction	(62,142)				(62,142)
8	Customer Deposits	(180,269)				(180,269)
9	Total Adjustments	(242,411)				(242,411)
10	**WORKING CAPITAL**					
11	Materials & Supplies	110,026				110,026
12	Mountainview Emission Credits	6,901				6,901
13	Working Cash	171,928				171,928
14	Total Working Capital	288,855				288,855
15	**DEDUCTIONS FOR RESERVES**					
16	Accumulated Depreciation Reserve	(10,591,544)				(10,591,544)
17	Accumulated Amortization	(918,847)				(918,847)
18	Accum. Def. Taxes - Plant	(3,513,106)				(3,513,106)
19	Accum. Def. Taxes - Capitalized Interest	(127,416)				(127,416)
20	Accum. Def. Taxes - CIAC	85,872				85,872
21	Accum. Def. Taxes - Vacation Accrual	24,604				24,604
22	Unfunded Pension Reserve	(74,696)				(74,696)
23	Total Deductions for Reserves	(15,115,133)				(15,115,133)
24	**RATE BASE**	17,552,216	147,280	1,837	(323,662)	17,375,834
25	**DEPR'N & AMORT EXPENSE**	1,483,187				1,532,287

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Total Weighted Average Plant
Thousands of Dollars

Line No.	Class of Plant	CPUC Adopted
1.	PLANT	
2.	Generation	
3.	Nuclear	
4.	San Onofre	-
5.	Palo Verde	1,915,572
6.	Other Production	879,347
7.	Coal	-
8.	Mountainview	726,957
9.	Hydro	1,221,288
10.	Total Generation	4,743,164
11.	Transmission	
12.	Land	106,665
13.	Substations	2,213,191
14.	Lines	1,429,857
15.	Total Transmission	3,749,713
16.	Distribution	
17.	Land	117,930
18.	Substations	2,661,417
19.	Lines	16,956,500
20.	Total Distribution	19,735,847
21.	General	2,667,439
22.	TOTAL PLANT	30,896,163
	INTANGIBLE PLANT	
23.	Radio Frequency	17,615
24.	Hydro Relicensing	150,416
25.	Miscellaneous Intangibles	481
26.	Capitalized Software	1,556,232
27.	TOTAL INTANGIBLE PLANT	1,724,744
28.	TOTAL PLANT IN SERVICE	32,620,907

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Working Cash
Thousands of Dollars

LINE NO.	ITEM	CPUC Adopted
	Operational Cash Requirement	
1.	Cash	0
2.	Special Deposits	266
3.	Working Funds	133
4.	Prepayments	48,997
5.	Other Accounts Receivable	32,605
	Less:	
6.	Employees' Withholding and Accrued Vacation	79,470
7.	Long-Term Incentive Plan	0
8.	Workers Comp & Inj. & Dam. Claims	65,375
9.	User Taxes	24,560
10.	Edison Smart Connect Adjustment	0
11.	Total Operational Cash Requirement	(87,404)
12.	Working Cash Capital Required as a Result of Paying Expenses in Advance of Collecting Revenues	259,333
13.	Net Amount of Working Cash Capital Supplied by Investors	**171,929**

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Development of Average Lag In Payment Of Operating Expenses
(Thousands of Dollars)

LINE NO.	Description	Expenses	AVERAGE NO. OF DAYS LAG	DOLLAR-DAYS LAG
1.	Fuel	324,207	35.36	11,465,445
2.	Purchase Power QF USPS	1,614,193	52.26	84,359,639
3.	Purchase Power QF EFT	908,540	44.38	40,318,002
4.	Purchase Power Non-QF	2,749,593	23.04	63,362,999
5.	Subtotal (Lines 1-4)	5,596,533	35.65	199,506,086
	Transmission -Distribution - Customer Accounts - Customer Service & Information - Admin. & Gen.			
6.	Company Labor	963,501	11.65	11,224,786
7.	Company Labor - Results Sharing	94,103	257.55	24,236,431
8.	Other O&M	689,822	43.79	30,208,964
9.	Goods & Services	752,126	45.19	33,988,590
10.	Materials Issued from Stores	19,580	0.00	0
11.	Insurance Provisions	18,973	0.00	0
12.	Injuries & Damages Provisions	116,776	0.00	0
13.	Funded Pension Provisions	88,326	(15.91)	(1,405,064)
14.	Benefits & Unfunded Pension Provisions	64,116	3.19	204,422
15.	P.B.O.P Provisions	44,573	110.73	4,935,568
16.	Franchise Requirements	106,870	262.84	28,089,820
17.	Uncollectibles	29,894	0.00	0
18.	CPUC Reimbursement Fees	0	0.00	0
19.	Sub-Total (Lines 6 - 18)	2,988,661	43.99	131,483,516
20.	Depreciation	1,705,441	0.00	0
21.	Decommissioning	22,726	24.00	545,432
22.	Taxes - Other Than Income	305,044	33.14	10,109,861
23.	Taxes - Based on Income	387,484	64.66	25,053,393
24.	Mountainview - O&M	0	0.00	0
25.	Mountainview - Depreciation	0	0.00	0
26.	Mountainview - Taxes	0	0.00	0
		0	0.00	0
27.	Total Operating Expenses	11,005,890	**33.32**	366,698,288
28.	Average Days Lag in Collection of Revenues	42.46		
29.	Average Days Lag in Payment of Expenses	33.32		
30.	Excess Revenue Lag	9.14		
31.	Average Daily Expense	30,153		
32.	Working Cash	275,649		

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Operation And Maintenance Expenses
(Nominal $000)
Category: Other Operating Revenue

Line No.	Account No.	Description	CPUC Adopted
1.	450.100	Late Payment Charges - C&I	4,314
2.	450.150	Late Payment Charges - Residential	7,250
3.	451.110	Returned Check Charges	965
4.	451.250	Service Establishment Charge	4,593
5.	451.300	Connection Charge - Residential	2,002
6.	451.310	Connection Charge - Non Residential	17
7.	451.780	Miscellaneous Revenue - Recovery Unauthorized use non-energy	156
8.			19,297
9.	450	Forfeited Discounts - remaining accounts	-
10.	451	Miscellaneous Service Revenues - remaining accounts	1,295
11.	453	Sales of Water and Water Power	315
12.	454	Rent from Electric Property	48,332
13.	456	Other Electric Revenues	78,034
14.		Gains/Losses on Sale of Property	218
15.		TOTAL OTHER OPERATING REVENUE	147,491

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Net-To-Gross Multiplier

Line No.	Description	CPUC Adopted
1.	Revenues	1.00000
2.	Uncollectibles Tax Rate	0.00238
3.	Uncollectibles Amount Applied	1.00000
4.	Uncollectibles Juris.	0.00238
5.	Subtotal	0.99762
6.	Franchise Fees Tax Rate	0.00910
7.	Franchise Fees Amount Applied	1.00000
8.	Franchise Fees Juris.	0.00910
9.	Subtotal	0.98853
10.	Arizona/New Mexico Income Tax Rates	0.00027
11.	Other State I.T. Amount Applied	0.98853
12.	Other State I.T. Juris.	0.00027
13.	Subtotal	0.98826
14.	S. I. T. Rate	0.08840
15.	S. I. T. Amount Applied	0.98853
16.	S. I. T. Juris.	0.08739
17.	Subtotal	0.90087
18.	Federal Income Tax	0.35000
19.	Federal Income Tax Amount Applied	0.98826
20.	Federal Income Tax Juris.	0.34589
21.	Net Operating Revenues	0.55498
22.	Uncollectible and Franchise Fees Factor	1.01161
23.	State & Federal CompositeTax Factor	1.67567
24.	**N-T-G MULTIPLIER**	**1.8019**

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Nuclear Refueling O&M Expense
(Thousands of Dollars)

Line No		Cost per Refueling 2012 $	Cost per Refueling 2015 $
1.	SONGS 2&3		
2.	Labor	-	-
3.	Non Labor	-	-
4.	Total	-	-
5.	Less Participants	-	-
6.	SCE Share	-	-

Appendix C
Southern California Edison
Test Year 2015 General Rate Case
Jurisdictional Allocation
(Thousands of Dollars)

Line No.	Item	Estimated 2015 Total	Estimated 2015 FERC	Estimated 2015 CPUC-GRC	% for 2015 FERC %	% for 2015 CPUC-GRC %	% for 2015 Total %
1.	**TOTAL OPERATING REVENUES**	6,179,829	997,533	5,182,297	16.14%	83.86%	100.00%
2.	**OPERATING EXPENSES:**						
3.	Production						
4.	Steam	9,362	-	9,362	0.00%	100.00%	100.00%
5.	Nuclear	73,695	-	73,695	0.00%	100.00%	100.00%
6.	Hydro	52,850	-	52,850	0.00%	100.00%	100.00%
7.	Other	116,944	-	116,944	0.00%	100.00%	100.00%
8.	Subtotal Production	252,851	-	252,851	0.00%	100.00%	100.00%
9.	Transmission	172,600	81,211	91,389	47.05%	52.95%	100.00%
10.	Distribution	519,191	4,407	514,783	0.85%	99.15%	100.00%
11.	Customer Accounts	168,209	-	168,209	0.00%	100.00%	100.00%
12.	Uncollectibles	14,685	2,374	12,311	16.17%	83.83%	100.00%
13.	Customer Service & Information	37,948	-	37,948	0.00%	100.00%	100.00%
14.	Administrative & General	805,493	47,679	757,814	5.92%	94.08%	100.00%
15.	Franchise Requirements	56,203	9,073	47,131	16.14%	83.86%	100.00%
16.	Revenue Credits	(193,280)	(45,789)	(147,491)	23.69%	76.31%	100.00%
17.	Subtotal	1,833,900	98,955	1,734,945	5.40%	94.60%	100.00%
18.	Escalation	108,225	6,274	101,951	5.80%	94.20%	100.00%
19.	Depreciation	1,754,541	222,252	1,532,289	12.67%	87.33%	100.00%
20.	Taxes Other Than On Income - Property	239,412	54,841	184,571	22.91%	77.09%	100.00%
21.	Taxes Other Than On Income - Payroll	64,940	3,844	61,096	5.92%	94.08%	100.00%
22.	Taxes Based On Income	396,381	199,360	197,020	50.30%	49.70%	100.00%
23.	Total Taxes	700,732	258,046	442,687	36.83%	63.17%	100.00%
24.	**TOTAL OPERATING EXPENSES**	4,397,399	585,528	3,811,871	13.32%	86.68%	100.00%
25.	**NET OPERATING REVENUE**	1,782,430	412,005	1,370,425	23.11%	76.89%	100.00%
26.	**RATE BASE**	22,591,091	5,215,256	17,375,834	23.09%	76.91%	100.00%
27.	**RATE OF RETURN**	7.89%	7.90%	7.89%			

(End of Appendix C)

APPENDIX D

~~2016 AND 2017~~POST-TEST YEAR RESULTS

Appendix D
Southern California Edison
Test Year 2015 General Rate Case
2016 and 2017 Summary of Earnings
Thousands of Dollars

Line No.	Item	CPUC Adopted 2016	CPUC Adopted 2017	Legacy Meters 2016	Rate Base Adjustment 2016	Legacy Meters 2017	Rate Base Adjustment 2017	CPUC Total 2016	CPUC Total 2017
1.	**TOTAL OPERATING REVENUES**	5,363,901	5,634,316	64,500	(36,928)	64,500	(35,508)	5,391,473	5,663,308
2.	**OPERATING EXPENSES:**								
3.	Production								
4.	Steam	9,362	9,362					9,362	9,362
5.	Nuclear	73,695	73,695					73,695	73,695
6.	Hydro	52,850	52,850					52,850	52,850
7.	Other	116,944	116,944					116,944	116,944
8.	Subtotal Production	252,851	252,851	-	-	-	-	252,851	252,851
9.	Transmission	91,389	91,389					91,389	91,389
10.	Distribution	514,783	514,783					514,783	514,783
11.	Customer Accounts	167,992	168,209					167,992	168,209
12.	Uncollectibles 1/	12,766	13,410	131	(88)	131	(85)	12,809	13,456
13.	Customer Service & Information	37,948	37,948					37,948	37,948
14.	Administrative & General	761,745	767,541					761,745	767,541
15.	Franchise Requirements 2/	48,785	51,244	584	(336)	584	(323)	49,033	51,506
16.	Revenue Credits	(149,299)	(149,047)					(149,299)	(149,047)
17.	Subtotal	1,738,961	1,748,328	715	(424)	715	(407)	1,739,252	1,748,636
18.	Escalation	154,927	205,001	-	-	-	-	154,927	205,001
19.	Depreciation	1,497,028	1,526,382	49,100		49,100		1,546,128	1,575,482
20.	Taxes Other Than On Income	264,694	286,101					264,694	286,101
21.	Taxes Based On Income	216,948	262,586	5,170	(11,882)	5,170	(11,425)	210,236	256,331
22.	Total Taxes	481,642	548,687	5,170	(11,882)	5,170	(11,425)	474,930	542,431
23.	**TOTAL OPERATING EXPENSES**	3,872,557	4,028,398	54,985	(12,306)	54,985	(11,833)	3,915,236	4,071,550
24.	**NET OPERATING REVENUE**	1,491,344	1,605,919	9,514	(24,622)	9,514	(23,675)	1,476,236	1,591,758
25.	**RATE BASE**	18,877,774	20,328,082	147,280	(311,675)	147,280	(299,687)	18,713,379	20,175,675
26.	**RATE OF RETURN**	7.90%	7.90%	6.46%	-7.90%	6.46%	-7.90%	7.89%	7.89%

(End of Appendix D)