BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application Of Southern California Edison Company (U 338E) For Authority To Increase Its Authorized Revenues For Electric Service In 2018, Among Other Things, And To Reflect That Increase In Rates.	A.16-09-001 (Filed September 1, 2016)

OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U338-E)

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State of Connecticut Public Utilities Regulatory Authority, Decision dated December 14, 2016, in Docket No. 16-06-04, *Application of the United Illuminating Company to Increase its Rates and Charges* 244, 249

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application Of Southern California Edison Company (U 338E) For Authority To Increase Its Authorized Revenues For Electric Service In 2018, Among Other Things, And To Reflect That Increase In Rates.	A.16-09-001 (Filed September 1, 2016)

OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U338-E)

1. POLICY

1.1. Introduction

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure, the Scoping Memorandum issued in this proceeding, and the Administrative Law Judges' (ALJs') follow-up email rulings, SCE respectfully submits its opening brief supporting its General Rate Case (GRC) Application for Test Year 2018.

SCE's rate case has been thoroughly vetted. As just one measure of this, as of the date that SCE submitted its rebuttal, SCE had answered nearly 8,000 data requests.[1] SCE continued to answer numerous data requests even during the evidentiary hearings. SCE submitted more than 4,200 pages of direct and supplemental testimony, and more than 5,100 pages of rebuttal testimony. SCE also presented at several "deep dive" workshops attended by the Administrative Law Judges (ALJs), the parties, and Commission Staff.[2] At these workshops, SCE reviewed key parts of our showing in detail, and answered questions.

The procedural schedule adopted by the Assigned Commissioner and ALJs provided an extensive opportunity to test and clarify the written testimony. Following a Prehearing Conference on

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[1] Exhibit SCE-17, p. 1, lines 7-8.
[2] President Picker attended a portion of these workshops as his schedule permitted.

October 25, 2016, the ALJs presided over several days of public participation hearings in locations throughout SCE's service territory.[3] The Commission also held 15 days of evidentiary hearings in Los Angeles and San Francisco. The resulting evidentiary record amply supports the reasonableness of SCE's request. That record and the applicable law and regulatory policies are discussed in the following sections of this brief.

For the sake of efficiency, this brief focuses on the contested areas of this case. The appendices to the brief provide a reference tool for the ALJs to pinpoint the various uncontested areas in SCE's request. The appendices address: (a) uncontested capital requests; (b) uncontested O&M requests; and (c) uncontested memorandum and balancing account proposals. SCE respectfully requests that the final decision issued by the Commission confirm that each of the items found in the appendices is approved.

The Policy sections below are intended to illustrate certain critical themes that inform many of the detailed sections that follow.

1.2. SCE's Request Is Necessary To Build A Safer, More Reliable, and Resilient Modern Grid That Will Help Fulfill State And Commission Policies

The work SCE asks to do in this rate case cycle will help bring our customers a power grid that will fulfill their needs and expectations in the decades to come. While there necessarily is much talk in this case about the modernization of the grid, it is crucial to note that the work points, straight and true, toward the missions that have long defined our service to our customers:[4]

- **Safety** for both our employees and the public.
- **Reliability** as the communities we are privileged to serve depend to an ever-greater degree on 24/7 electric service in their work and personal lives, and as we manage increasingly older grid assets and infrastructure.
- **Resilience** in light of the constant threat of natural disasters and the increasing threat of malicious and expanding cyber-attacks.
- **Better Customer Service and Choices** as our customers' needs for information and energy management alternatives continue to expand and evolve.

There will be a great deal of detailed evidence and explanation in the pages that follow. But at the start, we want to be clear that this larger theme informs significant parts of our T&D request -- by

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[3] Additional public participation hearings will be occurring in November 2017.
[4] *See* Exhibit SCE-17, pp. 2-3; Exhibit SCE-01, pp. 17-19.

building modern technologies and capabilities onto our grid, we will maintain (and in some cases improve) the core responsibilities we have to our customers, our communities, and our regulators.

In that vein, we can quickly summarize the four basic grounds that justify our Grid Modernization proposal. *First*, we must improve reliability, in light of metrics that show that SCE's reliability is declining compared to historical levels and compared to other utilities.[5] The need to act here is further validated by examining independent surveys of customers' demands and feedback. These independent inquiries to our customers show that they are indeed concerned about reliability. In fact, the recent feedback from J.D. Power and Associates found in the evidentiary record shows that SCE ranks in the top, or best, quartile in customers' satisfaction with the price of SCE's services, but only in the third quartile in power quality and reliability.[6] SCE even ranks in the fourth quartile in one sub-category of power quality and reliability.[7] An IEEE reliability survey also relegated SCE to the third quartile.[8] Improving this level of reliability requires system improvements.

Second, we have focused on foundational, "no-regrets" projects that will benefit our customers under all realistic future scenarios. These projects are primarily needed to promote safety and reliability, and have the added benefit of giving us the flexibility to accommodate high Distributed Energy Resource (DER) growth in the future.[9] ORA and other parties are mistaken in contending that our Grid Modernization efforts must await the outcome of the Distribution Resources Plan (DRP) proceeding.[10] Our proposal is not premature. Moreover, in light of long-term DER growth projections,[11] increasing complexity of the distribution grid,[12] and ambitious State environmental policy goal deadlines,[13] we simply must begin our work now. Undertaking the work only after problems occur and trying to "catch up" will be inefficient, ineffective and costly.

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[5] SCE, Payne, Tr. 10/1220, 1255; Exhibit SCE-17, p. 14, lines 1-21.

[6] *See* SCE, Garwacki, Tr. 14/1986-87; Exhibit SCE-36. Section 20 (Affordability) of this Opening Brief also addresses this point.

[7] *See* Exhibit SCE-36 (sub-category of Power Quality & Reliability entitled "Supply electricity during very hot or very cold temperatures").

[8] *See* Exhibit SCE-18, Vol. 10A4, pp. 26-27. *See also* Section 4.10.1, below.

[9] SCE, Payne, Tr. 10/1227, 1240; Exhibit SCE-01, p. 17, lines 5-8.

[10] SCE, Payne, Tr. 10/1214-15; Exhibit SCE-17, pp. 22-23.

[11] SCE, Payne, Tr. 10/1254-55; Exhibit SCE-17, pp. 21-22.

[12] SCE, Payne, Tr. 10/1321-23.

[13] *See* Exhibit SCE-17, pp. 5-7; SCE, Payne, Tr. 10/1240, 1254-55

Third, our proposal is cost-effective, as evidenced by SCE's benefit-cost analysis (BCA). The BCA shows net benefits even though it does not show the entire spectrum of benefits because it only accounts for certain narrow, readily-quantifiable reliability benefits. SCE's analysis of the payback period of key Grid Modernization programs also demonstrates cost-effectiveness. Further, the other intervenors focus on cutting costs without regard to the reliability impacts. When comparing SCE's proposal to those suggested by the other parties, such as ORA's approach of maintaining historical levels of automation and TURN's scaled-down automation, only SCE's approach yields sufficient reliability results.[14]

Fourth, customer-site data sources, such as DER telemetry, inverters and Advanced Metering Infrastructure (AMI), are necessary but they are not sufficient to provide critical grid-wide visibility, control, and operational flexibility.[15]

The detailed sections below will reinforce that our Grid Modernization proposals are prudent, and will help meet State policy goals and deadlines for providing Californians with a greener energy future while improving system reliability. At the evidentiary hearings, Mr. Payne encapsulated the reasons for our request:

> [L]ooking at this three-year GRC period, there are foundational investments that we believe would be required such as replacing our 23-year-old telecommunications system that is unable to support future levels of automation, modernizing the grid in ways to improve reliability, many of the things that we've talked about in our testimony. And so for this GRC period we believe these are things that are necessary regardless of the amount of distributed energy resources that come after that.
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> However, we have said that these are foundational investments that put us on a path of achieving much larger goals and being able to integrate many more distributed energy resources in the future. So the point I was trying to make here in this paragraph was just that the term "grid modernization" seems to have become a bit of a lightning road, which I don't quite understand the reason for.
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> What we're proposing here is – are a set of investments that are necessary to modernize the grid, to meet customer expectations, to provide safe, reliable service and has the additional benefits of allowing us to integrate more and different variations of distributed energy resources.[16]

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[14] *See* Section 4.10.3, below.
[15] *See* Section 4.10.4, below.
[16] SCE, Payne, Tr. 10/1283-84.

1.3. Our Stand-Alone Infrastructure Replacement Programs Are Necessary But Not Sufficient

SCE remains committed to properly maintaining its grid and, as reasonably necessary, replacing its aging and deteriorated components. In addition to compliance-driven programs, SCE has developed a number of preemptive replacement programs. The Commission has supported these programs in SCE's 2009, 2012, and 2015 GRCs.[17] SCE showed how we have prudently increased the scope of these programs over the years.[18] But we must continue these programs until we reach steady state replacement levels. Mr. Payne and others discussed how many of our grid assets were installed back in the 1950s and 1960s and have exceeded their mean-time-to-failure or are very close to it.[19] These assets continue to age. Thus, our need to keep our aging system reliable and resilient for our customers drives infrastructure replacement, which in turn drives prudent increases in capital spending.[20]

Finally, it must be noted that these infrastructure replacement programs, standing alone, are simply not sufficient. They can help to maintain safety and stem the decline in reliability, but other changes are needed in how we configure and operate the grid so that we can improve both safety and reliability. That is why we must undertake the Grid Modernization work on behalf of our customers.

1.4. SCE's Pole-Loading Software Versions Improved From 2013 to 2015, But Consistently Ensured GO-95-Compliant Pole Replacements

TURN seeks very significant after-the fact disallowances based on the decisions SCE made with regard to the SPIDACalc pole-loading assessment software.[21] While the capability of the SPIDACalc software pole-loading improved and was refined, the record shows that:

- The version of SPIDACalc that SCE purchased in 2013 had limitations when it modeled a limited number of pole types. These limitations could not have been identified in the vendor selection process given SCE's operational needs at the time;[22]

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[17] *See* Exhibit SCE-17, p. 16, lines 7-9.
[18] *Id.* at pp. 16-17.
[19] *See* Exhibit SCE-01, pp. 10-11; Exhibit SCE-17, p. 28, lines 11-13. "Mean-time-to-failure" is the length of time an asset or device is reasonably expected to last in operation. *See* Exhibit SCE-01, p. 10, fn. 8.
[20] Exhibit SCE-17, p. 28, lines 13-15.
[21] *See* Exhibit TURN-12, pp. 1, 20-21; Exhibit SCE-02, Vol. 9, pp. 11-16; Exhibit SCE-25, Vol. 3, Attachment 1.
[22] SCE, Chiu, Tr. 16/2286-87. *See also* Exhibit SCE-25, Vol. 3, Attachment 1, pp. I-4 and I-5.

- Initial versions of the pole assessment software provided accurate modeling results 90% of the time.[23] In a limited number of instances, the software limitations yielded safety factor calculations that were *more, rather than less, conservative in terms of pole replacement safety*;[24]
- SCE worked continuously with SPIDA, the software vendor, to study what appeared to be unusual pole-loading results and make improvements;[25] and
- If SCE had halted its Pole-Loading Program until the SPIDA software yielded results that came as close as possible to modeling actual pole behavior in all circumstances, SCE would have inadvisably brought the urgent, safety-based program to a halt, right while the program was focused on assessing poles in high fire areas.[26]

In sum, SCE acted prudently in its handling of pole-loading software. Over time, SCE carefully balanced the interests of safety, GO 95 compliance, continuous improvement and lowest reasonable costs for its customers.[27]

1.5. Our Proposal To Gradually Increase Depreciation Expense Strikes The Right Balance For Competing Priorities

One important goal of performing an updated depreciation study every rate case is to forecast the future cost to remove millions of today's T&D assets in service. The Commission has repeatedly held that recovery of the future cost to remove assets should be treated no differently than recovery of the original cost of purchasing and installing them, which is in a "straight line"—evenly—over the average remaining life of the assets. The Commission's adopted method, enshrined for decades in its Standard Practice (SP) U-4, preserves intergenerational equity by making sure depreciation expense is allocated to the generations of customers enjoying the benefit of the assets over their useful life.

To achieve straight-line allocation, one must answer a first question—what is the *total* estimated cost of removal? SCE answered that question head on for each account using a rigorous study grounded in the data. Then for the second question—who should pay?—the Commission has options for determining *when* to allocate depreciation expense.

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[23] *See* Section 19.4, below.
[24] Exhibit SCE-25, Vol. 3, Attachment 1, pp. I-5 and I-6; Exhibit SCE-25, Vol. 3, pp. 49-50.
[25] Exhibit SCE-25, Vol. 3, pp. 47-51.
[26] *Id.* at pp. 42-44. *See* also Exhibit SCE-02, Vol. 9, p. 1, lines 7-9.
[27] *See* Exhibit SCE-17, p. 27, lines 4-11.

To answer the first question, we performed a quantitative analysis more detailed and data-rich than a traditional analysis normally uses, and we did so consistent with the Commission's explicit orders from the 2015 GRC largely in response to TURN's criticisms. Thus, for this GRC, we divided our five largest T&D accounts into sub-populations of like assets, calculated their per-unit cost to retire using recorded data from the prior seven years, and then applied the per-unit costs to our surviving plant quantities.[28] As a final step, we estimated the *timing* of the assets' retirement by relying on our largely undisputed life analysis, and applied an assumed inflation rate of 2.72%.[29] The overall method is intuitive and straightforward, but the undertaking was labor-intensive and unparalleled.

The result of our analysis would justify charging $976 million *more* of annual depreciation expense than what currently authorized net salvage rates for T&D assets alone would recover (applied to 2015 plant balances). This is leaving aside the over $1.5 billion of depreciation expense that would accrue every year—undisturbed—under the currently authorized rates.[30]

Accordingly, for T&D net salvage rates, we answered the second question by applying the principle of gradualism, which the Commission has invoked in the recent past to moderate depreciation expense increases. The Commission has acknowledged, and we do as well, that applying gradualism "involves inter-temporal equity trade-offs between current and future customers." But, in the Commission's words, "these inter-temporal equity issues must be weighed in relation to overall cost increases imposed on customers in each GRC cycle."[31] Given the imperatives, including "the many new programs being implemented in this GRC, overall cost increases at issue in this GRC relative to past GRCs are substantial."[32]

There is little dispute about what SCE's first-ever actuarial study produced for the average remaining life of the vast majority of T&D assets in this GRC.[33] However, TURN (alone) continues to urge the Commission to abandon straight-line recovery for cost of removal by leaving the first question unaddressed. Instead, TURN jumps immediately to the second question, using a recycled methodology the Commission has rejected in the past that would defer costs to future customers by asking them to pay the costs to retire assets that no longer serve them.

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[28] *See* Exhibit SCE-09, Vol. 3, Section II.B.
[29] Exhibit SCE-09, Vol. 3, p. 4 & p. 5, fn. 4.
[30] Exhibit SCE-09, Vol. 3A2.
[31] D.14-08-032, p. 599.
[32] *See* Section 18.5.1, below.
[33] *See* Section 18.3.1, below.

Because of this methodological divide between SCE and TURN, our pending proposal compared to TURN's results in only a 4% difference—$65 million out of a total $1.6 billion—in CPUC-jurisdictional depreciation expense requested. SCE's proposal, though moderated, represents a step towards achieving SP U-4's objectives of straight-line recovery, while TURN's proposal seeks to defer unavoidable future removal costs.

Applying gradualism in one GRC cycle does not mean indefinite suspension of inter-generational equity. As the Commission noted, "[d]epending on conditions prevailing in future GRC cycles, ratepayers may be better positioned to absorb removal cost increases in comparison to today's customers."[34] Although we have every reason to be confident that our analysis produced a solid estimate of the future cost of removal, we recognize that increasing proposed depreciation expense by nearly $1 billion dollars per year would contribute to rate impacts too dramatic for our customers to bear at a time when we are balancing rate increases against the time-sensitive imperatives we identified above to modernize our grid, replace our aging infrastructure, and give our customers the increased reliability they want and deserve.

1.6. In Forecast-Based Ratemaking, Management Must Have Some Discretion to Vary Spending To Meet Emergent Needs And Address Post-Application Developments

Another theme that has developed in this case is an examination of authorized versus recorded spending. In some instances, SCE spent less money than authorized on a given project or activity. In other instances, SCE spent more money than the Commission authorized.[35]

As a starting matter, under forecast-based ratemaking SCE cannot be expected to generate perfect forecasts, nor be required to do so.[36] SCE must instead develop reasonable estimates of what it projects to spend, consistent with the needs of the electric system to safely and reliably serve the needs of our customers. (These projections must be developed more than a year-and-a-half before the test year even commences.) Then, when the Commission decides on those forecasts, the Commission necessarily relies on facts, arguments, and assumptions that may be different from the actual system realities and

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[34] D.14-08-032, p. 600.

[35] *See* Exhibit SCE-17, p. 30, lines 3-6.

[36] *See generally In Re Valencia Water Co.*, D.07-06-024, p. 39, 2007 WL 1855274, at *22 (June 21, 2007) ("Because we base public utility rates on future test years, it is necessary for utilities to forecast customer growth, usage, capital additions, expenses, and other factors as part of their GRC applications. The goal is to make reasonable estimates that will allow the utility the opportunity to earn a fair return on its rate base.").

customer demands that the utility faces when the time comes to actually spend the authorized amounts.[37] In addition, if a rate case decision is issued during the Test Year rather than before the commencement of the Test Year, then the authorized amounts may only be known after the dollars have been spent or are in the process of being spent.

The Commission has repeatedly ruled that utilities have the flexibility to use their best judgment to manage the business.[38] SCE also rebutted in detail TURN's suggestion that the Commission deny SCE recovery when SCE spends on programs in excess of what the Commission has authorized.[39]

The key here is that SCE's management has the responsibility to manage and operate the system safely and reliably, and necessarily must have discretion to spend differently than authorized if system or customer needs or emergent circumstances so dictate.

Mr. Payne testified on this issue at the evidentiary hearings in response to questions from ALJ Roscow:

> Q And I'm asking you a different question, which is, why do you, as Edison's CEO, think that Edison has the latitude to move funds that the Commission has designated for one purpose away from that purpose into a different purpose?
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> A I think the answer to that lies in the responsibility that we have, which is we have the responsibility to operate the electric system safely and reliably. And we engage in forecast ratemaking, which is our best estimate of what it is that we think we are going to need for a several-year period. And there are undoubtedly things that come along that change our view of what the priorities are in any given year.
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> Because we have that responsibility, we have – and you see in the last line of this paragraph that you're referring to in my testimony, it says: The utility has the obligation to maintain its operations and its plant in the condition to provide efficient, safe, reliable service even if that condition requires more expenditures than the Commission's authorized.
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> So, again, the way we do ratemaking is it's done through forecasts, and the only way for us to couple the responsibility that we have with the type of funding that we have is to have a level of management discretion that allows us to reprioritize to the things that create the most value for customers. That's how we view management discretion overall, that it lines

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[37] *See In Re Sw. Gas Corp*., D.04-03-034, 232 P.U.R. 4th 353, 2004 WL 673088 at *10 (Mar. 16, 2004) ("The purpose of a general rate case is to develop and adopt sound, informed estimates of the reasonable costs to be incurred in the test year. We know that our adopted levels of revenues and expense may be at variance with actual experience.").

[38] *See*, e.g., *Re* California-*American Water* Co., D.02-07-011, pp. 6-7, 2002 Cal. PUC LEXIS 423, 220 P.U.R. 4th 556.

[39] *See* Exhibit SCE-17, p. 30, lines 3-13; Exhibit SCE-25, Vol. 3, Chap. III.

> up with our overall responsibility to get good results in how we manage and operate the grid.[40]

2. EVIDENTIARY STANDARDS AND THE BURDEN OF PROOF

A utility seeking a rate increase has the ultimate burden of proving that its request is reasonable.[41] In its decision on SCE's 2012 GRC, the Commission confirmed that the burden of proof, which had, on occasion, previously been described as "clear and convincing evidence," was actually a "preponderance of evidence."[42]

SCE's 2009 GRC decision also clarified that the correct standard is the "preponderance of evidence."[43] This conforms Commission practice to California's Evidence Code, which states: "except as otherwise provided by law, the burden of proof requires proof by a preponderance of the evidence."[44] Most recently, the Commission also adopted the "preponderance" standard in SCE's 2015 GRC.[45]

The Commission has also recognized the important distinction between the burden of proof and the burden of producing evidence:

> [W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof. The burden of going forward to produce evidence relates to raising a reasonable doubt as to the utility's position and presenting evidence explaining the counterpoint position. Where this counterpoint causes the Commission to entertain a reasonable doubt regarding the utility's position, and the utility does not overcome this doubt, the utility has not met its ultimate burden of proof.[46]

As this brief will demonstrate, there are many instances where SCE has introduced evidence supporting its requests, yet no other party has met the burden of going forward with a contrary position. In these many instances, SCE must be found to have met its burden of proof.

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[40] SCE, Payne, Tr. 10/1315-1316.

[41] *Re Southern* Counties *Gas Co*., D.60614, 58 CPUC 27, 34 (1960); *Re Southern California Gas Co*., D.60615, 58 CPUC 57 (1960); *Re Suburban Water Co*., D.64256, 60 CPUC 183 (1962).

[42] D.12-11-051, p. 9.

[43] D.09-03-025, p. 8.

[44] Cal. Evid. Code §115. As the Commission has pointed out: "The preponderance of the evidence is generally the default standard in civil and administrative law cases." *Re San Diego Gas & Electric Co*., D.08-12-058, p. 19, citing California Administrative Hearing Practice, 2d Ed (2005) at 365.

[45] D.15-11-021, pp. 8-9.

[46] *Re Pacific Bell*, D.87-12-067 at p. 22, 27 CPUC2d 1. *See also Universal Studios Inc. v. Southern California Edison Co*., D.04-04-074, pp. 31-32, 2004 Cal. PUC LEXIS 173; *Re Golden State Water Co*., D.07-11-037, 2007 Cal. PUC LEXIS 648.

3. SETTLEMENTS

Appendix B to the Scoping Memo provided the Adopted Proceeding Schedule for this proceeding. In that schedule, the Commission encouraged settlement discussions to occur in the May-June 2017 timeframe. Certain settlement discussions did indeed transpire with several parties before, during, and after that timeframe. SCE arrived at a settlement with the City of Lancaster. Also, SCE and Small Business Utility Advocates (SBUA) reached stipulations that resolved all issues between them. Currently, SCE does not anticipate that the briefing schedule, additional public participation hearings, update hearings, or any other steps in the timely processing of this case will be affected by any settlement-related items.

4. TRANSMISSION AND DISTRIBUTION

4.1. T&D – General

4.1.1. Operational Overview

In SCE's opening showing, SCE explained how its Transmission and Distribution (T&D) proposals support SCE's strategic objectives.[47] SCE also forecast benefits springing from T&D's operational and service excellence (OpX) efforts. No party directly challenged these forecast OpX benefits. However, intervenor parties did not take the forecast benefits into account when proposing reductions to both the Overhead Conductor Program (OCP) and the Poles Program. This results in "double-counting" forecast reductions.[48] In rebuttal, SCE explained why the OpX benefits must be factored in if reductions are adopted.[49]

For the Poles Program, TURN recommended a reduction of $1,645 per distribution pole replacement. But TURN did not tackle in any way the overlap between its proposed reduction and SCE's forecast OpX savings. This overlap averages approximately $1,100 per distribution pole.[50] Put another way, TURN is proposing a reduction of $1,645 per pole in addition to SCE's proposed OpX benefit of $1,100 as included in the Pole Program forecast. So even if the Commission were to adopt

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[47] Exhibit SCE-18, Vol. 1, p. 1, lines 3-7.

[48] *Id.* at pp. 3-4.

[49] *Id*. For example, the 2016 recorded costs for the OCP were lower than SCE's forecast unit costs, and the effectiveness of T&D OpX initiatives was one of the primary drivers. No other party proposed forecasts based on the 2016 recorded costs for OCP. But if the Commission were to use 2016 recorded costs as the basis for adopted funding, then the Commission should incorporate the OpX benefits. *Id*. at p. 4, lines 1-5.

[50] *Id*. at p. 4, lines 7-13.

TURN's proposed reduction, or indeed any reduction at all, the Commission must modify that reduction to reflect the savings that SCE has shown.[51]

4.1.2. Risk-Informed Decision Making

While SCE's risk-informed planning approach is relatively new, it has influenced some operational decisions and scoping efforts; it was also one of many factors considered in funding allocation decisions for this GRC.[52] However, SCE's risk analysis and resulting risk spend efficiency (RSE) metric "has not matured sufficiently to drive our 2018 GRC request at a program or project level."[53] ORA agreed with this viewpoint.[54] But some intervenors tried to use SCE's analysis to make spending recommendations for the Overhead Conductor Program (OCP) and Grid Modernization Program.

SCE showed why its preliminary risk analysis for OCP and the initial results cannot be used to determine the right level of funding for SCE's OCP request in this GRC.[55] TURN in fact criticized SCE's preliminary risk analysis for OCP and then turned around and attempted to use SCE's analysis to justify reducing the authorized funding for OCP.[56] TURN also took scoring results from a preliminary set of mitigations (a number of which had not been tested or deployed on SCE's systems) and attempted to use that preliminary information to, in effect, redesign SCE's OCP. SCE carefully showed why, prior to the development of more comprehensive risk-informed planning, substituting this type of preliminary information in place of proven solutions would not be a reasonable strategy at this time for reducing the risks to the public, to first responders, and to SCE employees that can follow from wire down events.[57]

4.1.3. Safety and Reliability Investment Incentive Mechanism

The Safety and Reliability Investment Incentive Mechanism (SRIIM) comprises two components: (1) capital expenditures focused closely on core safety and reliability-related projects and programs; and (2) the hiring of craft employees who perform the work on safety and reliability-related

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51 *Id.*
52 Exhibit SCE-18, Vol. 1, p. 11, lines 21-23; SCE-14, p. 22.
53 Exhibit SCE-14, p. 53.
54 See Exhibit ORA-05, p. 2.
55 Exhibit SCE-18, Vol. 1, pp. 12-13.
56 *Id.* at pp. 13-14.
57 *Id.* at pp. 14-15.

projects and programs.[58] SCE proposes continuing SRIIM for this rate case cycle, with three enhancements to the capital mechanism and four enhancements to the workforce mechanism.[59]

The three capital mechanism enhancements are:

- Change the programs included in SRIIM by adding OCP and 4kV Overload-Driven Cutovers;[60]
- Set the capital target based on the actual level of capital expenditures that the Commission authorizes;[61] and
- Delineate that any spending occurring in the High Priority[62] categories in excess of authorized amounts (absent certain conditions adopted in SCE's 2015 GRC) can be used to achieve the targets established for the SRIIM capital categories. This helps account for unforeseen conditions that are beyond SCE's control.

SCE also proposed financial consequences if SCE fails to achieve the workforce targets.[63] We suggested four enhancements to the existing SRIIM workforce mechanism:

- Add foreman/troubleman trainer and operator trainee classifications;
- Increase the headcount target from 2,225 to 2,375;
- Adjust the headcount target by one-half the percentage change in the authorized versus requested T&D capital; and
- Change the measurement period from a single day to a more reasonable actual time frame, so that if SCE meets the headcount during the designated time frame, it will be deemed to have satisfied the workforce component of SRIIM.[64]

SCE also showed that the SRIIM workforce mechanism must be linked to the authorized capital. It is simply unfair to SCE, its workforce, and ultimately its customers to force SCE to hire additional

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[58] Exhibit SCE-02, Vol. 1, p. 16, lines 10-13.

[59] *Id.* at pp. 17-22.

[60] SCE originally proposed eliminating Underground Structures and Underground Switch Replacements. *See* Exhibit SCE-02, Vol. 1, p. 18, lines 10-12. But SCE ultimately agreed with CUE's view that these programs should be retained in SRIIM. SCE also conceded to CUE's argument that 4kV Substation Elimination should be added to SRIIM. *See* Exhibit SCE-18, Vol. 1, p. 9, lines 4-10.

[61] Exhibit SCE-02, Vol. 1, p. 18, lines 14-16.

[62] "High Priority" encompasses emergent conditions that are beyond SCE's control – specifically, customer-driven growth, storms, and claims. *See* Exhibit SCE-02, Vol. 1, p. 18, lines 10-12 and p. 19, lines 17-21.

[63] *See* Exhibit SCE-18, Vol. 1, pp. 5-6. SCE suggested continuing the timing mechanism established in SCE's 2015 GRC, so that if any workforce develops in the fourth quarter of 2020, SCE is given the first quarter of 2021 to address that shortfall. *Id.* at p. 6, lines 1-3.

[64] *See* Exhibit SCE-2, Vol. 1A, p. 22, lines 4-9; SCE-18, Vol. 1, p. 6, lines 4-10 and p. 10, lines 3-4.

employees if the related authorized scope of work is reduced by the Commission.[65] For example, ORA has proposed more than a 20% reduction for 2018; if the Commission were to adopt this, it would not be reasonable to concurrently swell SCE's workforce regardless of the adopted reductions.[66] SCE also explained that, to the degree the Commission recommends higher SRIIM workforce counts, additional funds for training programs will be needed to provide proper employee training (including safety training). At a minimum, on a percentage basis, for every one percent increase in SRIIM employee headcount a ten percent increase in Training Seat-Time for Transmission and Distribution Personnel is warranted.[67]

4.2. Customer-Driven Programs

SCE's Customer-Driven programs are pursued to meet SCE's obligation to serve its customers, and are subject to SCE's Preliminary Statement and by Tariff Rules 2, 15, 16, and 20.[68] Our Customer-Driven Programs include the capital expenditures that SCE incurs when responding to requests from our customers. Thus, the level of capital expenditures in this area is largely outside of SCE's control, since the amount of spend will pivot based on the number and type of customer requests, as well as other external factors such as permitting.[69]

As SCE testified, customer growth-related work activities ultimately revolve around meter installations.[70] Consistent with the forecasting methodology that the Commission adopted in SCE's 2012 and 2015 GRCs, SCE has used a meter set forecast to develop its capital expenditure forecasts for each new service connection work category.[71] Thus, many of the disputes between SCE and other parties in customer-driven activities will ultimately be resolved by the meter set forecasts that the Commission adopts in its final GRC decision.[72]

In forecasting Residential Line Extensions, SCE showed that TURN's suggestion to add 2006 data to SCE's 2007-2015 regression analysis would result in a less accurate forecast.[73]

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[65] SCE-18, Vol. 1, p. 9, lines 16-18.
[66] Exhibit SCE-18, Vol. 1, p. 9, lines 16-19 and fn. 19.
[67] *Id.* at pp. 9-10.
[68] *See* Exhibit SCE-18, Vol. 2, p. 1, lines 3-6.
[69] *Id.* at p. 1, lines 6-7.
[70] *See*, e.g., Exhibit SCE-02, Vol. 2, p. 4, lines 18-25.
[71] Exhibit SCE-18, Vol. 2, p. 4, lines 9-15.
[72] *See*, e.g., Exhibit SCE-18, Vol. 2, p. 6, lines 2-3, 12-13.
[73] *Id.* at pp. 6-7.

In forecasting Residential Tract Development, TURN provided no explanation as to why TURN's average (which excluded the more recent historical years) serves as a better projection than SCE's use of the 10 *most recent* years of historical data.[74] SCE also showed that TURN's suggested use of excess inventory to justify a revised number of cable feet per meter is incorrect; SCE's workpapers in its opening testimony demonstrated that this inventory is now depleted.[75]

For Residential Backbone Development, SCE bases its forecast on a ten-year average, which captures the year-to-year variability during the housing bubble and decline.[76] SCE showed that TURN's use of a five-year average is less accurate in smoothing out the variability of this work area and taking into account historical developments.[77] TURN provided no evidence to explain why using a five-year average is a more reasonable estimate than averaging the last ten years.[78]

For Commercial Service Connections and Tract Development, SCE showed that the years prior to 2006 encompassed costs for a significant increase in work resulting from the then-robust housing market.[79] The recorded commercial meter sets for years 2000-2006 do not reflect the current-day commercial service connections and tract development, which are characterized by smaller-scale development.[80] Additionally, the years 2007-2009 reflect a time of significant market recession. During that recession period, SCE had excess inventory. But that inventory has now been fully depleted.[81] Because SCE's forecast more accurately reflects the current conditions, it should be adopted.[82]

4.2.1. Rule 20 Issues

SCE converts existing overhead facilities to underground facilities pursuant to Commission Tariff Rules 20A, 20B, and 20C. SCE selects conversion projects using the criteria established in the

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[74] *Id*. at p. 7, lines 7-20.
[75] *Id*. at pp. 7-8.
[76] *Id.* at p. 8, lines 4-28.
[77] *Id*. at pp. 8-9.
[78] *Id*. at p. 8, lines 15-19.
[79] *Id.* at p. 9, lines 3-8.
[80] *Id*. at p. 9, lines 8-11.
[81] *Id.* at p. 9, lines 11-13.
[82] *Id.* at p. 9, lines 14-23. Among other items, 2016 data demonstrates that SCE's forecast methodology is accurate for Commercial Service Connections. The 2016 cost per meter set was within eight percent of SCE's proposed cost per meter figure. *Id.* at lines 19-22.

tariff.[83] In turn, each governmental agency selects locations that meet these criteria within their jurisdiction. The work occurs in direct response to customer requests, and can fluctuate significantly from year to year based on the requests.[84] In SCE's last rate case, SCE used its forecast from the 2012 GRC as the basis for its projection of spending.[85] For the 2018 GRC, SCE looked to actual recorded costs, and developed its forecast based on a five-year average.[86] SCE also provided a detailed listing of the various cities within SCE's service territory that can participate in SCE's Rule 20A program, and highlighted whether the city contains a Disadvantaged Community (DAC).[87]

ORA proposed what it terms a "temporary penalty" for SCE based on ORA's concerns with underspending that might occur with respect to this work that occurs at the direction of the cities receiving Rule 20A funding.[88] ORA "recommends that the Commission adopt SCE's 2017 and 2018 forecasts for Rule 20A expenditures, but also incorporate a temporary 'penalty' to reflect the underspending that occurred in 2014 through 2016."[89] While ORA's explanation of the ratemaking aspects of its proposal is slightly unclear, ORA does state that "ORA is including an adjustment of $9.558 million in each of the years 2017 and 2018 (each year's proposed decrease represents one half of the $19.117 million that was underspent)."[90]

The trouble with ORA's proposal is that it inexorably leads to less Rule 20A work occurring. The annual Rule 20A budget is divided among the 208 cities and counties within SCE's service territory, according to the formula provided in the Rule 20 tariff. The allocation methodology results in a nonlinear distribution of the funds that are allocated to each city.[91] The penalty proposed by ORA would heavily impact the allocation for some cities and counties, with 18 cities receiving zero allocation.[92]

SCE showed that the penalty proposed by ORA would serve to further reduce the amount of expenditures toward Rule 20A projects because it would slow down accruals that allow for new projects

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[83] *Id.* at p. 10, lines 10-11.
[84] *Id.* at lines 12-16.
[85] SCE, Ayorinde, Tr. 9/1085.
[86] *Id.* ("So in the previous forecast was based on – for the 2015 rate case was based on the forecast we had from 2012, and for 2018 rate case we're looking at recorded, the actual recorded cost and taking a five-year average of that.")
[87] *See* Exhibit SCE-31, pp. 1-6.
[88] *See* Exhibit ORA-08, p. 59, lines 18-20.
[89] *Id.*
[90] *Id.* at p. 59, lines 22-24.
[91] *See* Exhibit SCE-18, Vol. 2, p. 11, lines 7-10.
[92] *Id.* at lines 11-12.

to be proposed and potentially delay currently mortgaged projects.[93] At the evidentiary hearings, SCE witness Adebola Ayorinde testified on this point in response to questions from the ALJs:

> Q: Would Edison do anything differently if the 9 and-a-half million dollar penalty was imposed?
>
> A: Yes, your Honor. I think part of what we would see, I think like I mentioned earlier, is in some cases, we might not be able to execute on some projects. Some cities that have been hoping and looking to the mortgaging, if their allocations are reduced, because if that penalty is imposed the budget will be reduced, which means the allocations will be reduced, which means they might not be able to execute on future projects.[94]

SCE also showed, on a project-by-project basis, what the impact would be if the Commission were to accept ORA's financial penalty recommendation.[95]

4.3. System Planning

SCE's System Planning operations is an annual process that identifies the specific programs and projects necessary for the ongoing design and operation of its transmission, subtransmission, and distribution systems. The annual process covers a wide array of projects for which SCE has requested capital expenditure funding in this GRC, including New Distribution Circuits, Substation Expansion Projects, 4kV Cutover and Substation Elimination Projects, Subtransmission Lines Plan, and Substation Equipment Replacement Program. ORA, TURN, and SEIA-Vote Solar oppose some of the funding for these capital projects.[96] These projects are necessary for SCE to continue to meet the load needs of our customers by adding capacity (when necessary) or to prudently modify the rapidly-changing electrical grid.[97] Below SCE responds to the specific criticisms of ORA, TURN, and SEIA-Vote Solar.

Before examining the shortcomings in ORA's specific proposed reductions to SCE's capital forecast, it is important to note at the outset the exhaustive amount of discovery, on-site job walks, tours, presentations and training documents SCE provided to ORA.[98] ORA Witness Tom Roberts confirmed this during evidentiary hearings:

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[93] *Id.* at pp. 11-12.
[94] SCE, Ayorinde, Tr. 9:1103-1104.
[95] *See* Exhibit SCE-31, pp. 7-8.
[96] No party opposed SCE's 2018 Test Year O&M forecast for System Planning and it should be approved in total. *See* Exhibit SCE-18, Vol. 3, p. 6, Table I-5.
[97] *See* Exhibit SCE-18, Vol. 3, p. 1.
[98] *See* Exhibit SCE-18, Vol. 3, p. 7.

> SCE provided … enormous amounts of information in response to my data requests. I don't think it is a question of volume. And I think, in general, Edison did a very good job of responding to my questions.[99]

4.3.1. New Distribution Circuits

For New Distribution Circuits, ORA suggests reducing SCE's 2017-18 capital expenditure forecast from $90.137 million to $67.463 million, based on SCE's 2016 actual recorded costs and then escalating SCE's 2016 forecast for 2017 and 2018.[100] But SCE performs its system planning analysis on a project-by-project basis using forecasts of future needs, rather than on the basis of historical spending amounts.[101] ORA does not contest the need for any specific projects SCE identified as necessary. The New Distribution Circuits SCE proposed are necessary to address identified system needs and to mitigate against unnecessary reliability and equipment risks to SCE's distribution system.[102] ORA's recommendation should be rejected.

4.3.2. Distribution System Upgrades

For Distribution System Upgrades, TURN proposes reducing SCE's 2017-18 capital expenditure forecast from $99.438 million to $92.238 million, arguing that wholesale DERs should pay for the cost of certain future upgrades instead of retail customers. SCE's rebuttal testimony explained that it forecasts future capacity upgrades based on anticipated future retail load, and that SCE already requires wholesale DERs to pay for upgrades they trigger at the time of interconnection pursuant to Tariff Rule 21.[103]

4.3.3. Substation Expansion Projects

For Substation Expansion Projects, ORA proposes a reduction in capital spending of $8.499 million (from SCE's proposed $224.101 million to $215.602 million) based on the argument that it does not believe that SCE will complete the Safari Substation during the current rate case cycle due to

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[99] Roberts, ORA, Hearing Tr. 18/2681.
[100] *See* Exhibit ORA-09, p. 74.
[101] *See* Exhibit SCE-18, Vol. 3, p. 11.
[102] *See* Exhibit SCE-18, Vol. 3, p. 11.
[103] *Id.* at p. 12.

community opposition.[104] That opposition is based on pure anecdote and speculation,[105] as confirmed by Mr. Roberts on the stand,[106] and should not be considered relevant evidence in this GRC.

4.3.4. Substation Equipment Replacement Program (SERP)

For SERP, ORA proposes a reduction in capital spending of $28.960 million (from SCE's proposed $49.875 million to $20.825 million). SCE acknowledges that its proposed 2017-2018 capital spend represents a material increase over 2015 authorized amounts. But SCE explained that its forecast was based on a study that was completed in 2016. This recent study demonstrated that the forecast amount is required to replace overstressed circuit breakers on SCE's system.[107] Mr. Roberts, the ORA analyst who is recommending the capital expenditure reductions, admitted that he did not understand the reliability- or safety-related risks underlying SERP.[108] The results of the study justifying the forecast are found in the evidentiary record.[109] SCE also demonstrated that it has the capacity to do the requested work, and that its unit cost forecast was reasonable.[110]

4.3.5. Subtransmission Lines Plan

For SCE's Subtransmission Lines Plan, ORA proposes a reduction in capital spending of $47.669 million (from SCE's proposed $205.582 million to $157.913 million) based on a four-year average of historical spend. But as SCE explained above, System Planning is done based on project-specific basis as determined by locational-specific grid needs, not some historical capital expenditure average. ORA's testimony ignores the locational-specific reality of subtransmission system projects. SCE also demonstrated that while it had experienced some permitting delays for two major projects in the forecast, it has now obtained Permits to Construct for those lines,[111] and that it has the resources and capability to complete the projects.[112] The Commission should reject ORA's proposed cuts to this critical grid work.

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[104] *See* Exhibit ORA-09, p. 75.
[105] Exhibit SCE-18, Volume 3, p. 15.
[106] Roberts, ORA, Hearing Tr. 18: 2696-97.
[107] Exhibit SCE-18, Volume 3, pp. 16-17.
[108] Roberts, ORA, Hearing Tr. 18: 2702.
[109] Exhibit SCE-18, Volume 3, Appendix A, pp. A-93-102.
[110] Exhibit SCE-18, Volume 3, pp. 17-18.
[111] Exhibit SCE-18, Volume 3, pp. 18-19.
[112] Exhibit SCE-18, Volume 3, pp. 19-20.

4.3.6. 4kV Programs

SCE's 4kV work consists of two important programs (4kV cutovers and 4kV substation eliminations) designed to replace the 20-25% of SCE's distribution system that is still served by an antiquated, low-voltage system not designed for today's modern electrical grid.[113] SCE explained that the programs are multi-faceted and have several, independent drivers, including: mitigating safety and reliability risks by replacing old and obsolete equipment, alleviating space constraints at the substation, providing operational flexibility, mitigating power quality concerns, preventing future overloads, and minimizing energy losses.[114]

4.3.6.1. 4kV Cutover program

For SCE's 4kV cutover program, ORA proposes a reduction in capital spending of $16.303 million (from SCE's proposed $72.618 million to $56.315 million), recommending that SCE continue to use an outdated forecast methodology based on "amps cutover" instead of "transformers removed." Although relieving overloaded amps is the problem the program is trying to solve, the way SCE solves the problem is by removing transformers and other physical electric equipment. ORA witness Roberts confirmed as much during cross-examination.[115] Moreover, the number of transformers that need to be replaced on a circuit in order to cut over a certain number of amps can vary significantly based on the specific characteristics of the circuit.[116] Accordingly, it was appropriate for SCE to change its cost forecasting methodology, improving it to focus on the number of transformers removed, not the number of amps cutover, as the physical equipment removal is what costs money.[117]

4.3.6.2. 4kV Substation Elimination Program

Despite the fact that the Commission authorized SCE's entire request for this important program in the 2015 GRC final decision, and despite the fact that SCE's many-decades-old 4kV substations are simply another rate case cycle older now, TURN recommends that the Commission eviscerate the program, arguing that the Commission should essentially authorize either de minimis or zero funding

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[113] Exhibit SCE-18, Volume 3, p. 20.
[114] Exhibit SCE-18, Volume 3, p. 20.
[115] Roberts, ORA, Hearing Tr. 18: 2687-88.
[116] Exhibit SCE-18, Volume 3, p. 23; *see also* Roberts, ORA, Hearing Tr. 18: 2688-89.
[117] Takayesu, SCE, Hearing Tr. 11:1481-82.

going forward.[118] TURN's argument is almost entirely based on a flawed cost-benefit analysis, which neither accurately captures the costs of running the system to failure (as TURN would do), nor properly accounts for all the benefits of the program. The Commission should reject TURN's proposal.

To start, TURN's cost-benefit analysis does not appropriately take into effect the real costs of the alternatives to the 4kV substation elimination program. In other words, TURN's run-to-failure proposal does not take into account the actual costs that would be incurred should SCE be forced to run these assets to failure. If the antiquated 4kV substations are not replaced proactively, they will need to be maintained, will eventually fail, and then presumably be rebuilt.[119] When these costs are appropriately taken into account, TURN's negative benefit-to-cost determination for the program is flipped on its head.[120]

Moreover, TURN's myopic focus on the SAIDI-driven reliability benefits of the substation elimination program does not give appropriate weight to other, less-quantifiable drivers that support the program. For example, SCE demonstrated that the lack of availability of obsolete equipment, the unreliability of old equipment, the limited physical space to upgrade or replace old equipment, the lack of transfer and operational flexibility, the difficulty of maintaining adequate voltage, insufficient capacity and high energy losses all represent reliability and safety risks to SCE's customers and employees and should not be ignored.[121] Mr. Takayesu touched on this during the evidentiary hearings:

> Those are two factors [obsolescence of equipment and decreasing reliability]. I believe we list four additional factors that drive 4 kV substation elimination, such as operating flexibility, space constraints, operation and maintenance concerns, and [DER] integration.[122]
>
> *****
>
> So the circuits that are part of the elimination are circuits that come out of the substations that have been identified for elimination. And the criteria by which we chose those substations, reliability is just one component. As I mentioned earlier, there are other factors

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[118] Stephens, TURN, Hearing Tr. 20: 2886-87.

[119] Exhibit SCE-18, Volume 3, pp. 22-26.

[120] Exhibit SCE-18, Volume 3, p. 27 and Table III-13. For this table, SCE used TURN's numbers except where highlighted in black. Due to the ALJ's July 17 ruling from the bench on a TURN motion to strike, the customer minutes interrupted number (CMI) is no longer current. That being said, the difference is immaterial to the equation for these purposes, and does not change the outcome that when considering the costs of the alternatives, SCE's proposal is cost-effective.

[121] Exhibit SCE-18, Volume 3, p. 24.

[122] SCE, Takayesu, Tr. 11/1408.

> besides reliability that we have to consider because the substation itself is what serves all the circuits and we are looking at the age and condition of all of the equipment inside that substation fence.[123]
>
> *****
>
> It does show if you take the top four substations, that you would have an impact on SAIDI. But I think this isn't inconsistent with what we have looked at reliability and the fact it's one factor out of many that drove the substation elimination programs. And what concerned us more was the rate of increase over time of the reliability performance across the substations, in addition to the fact that what was a higher incidence of reasons for interruptions were due to equipment failure. So, to us, it was a combination of not just looking at one year. You have to look at multiple years and we would like, you know, we believe the best way to look at those is to consider the trajectory in those years.[124]

In sum, the record demonstrates that SCE's 4kV proposals will prudently address safety, reliability, and power quality concerns, and will continue the replacement of the portion of SCE's grid that is still served by an antiquated, low-voltage system. The proposed reductions by ORA and TURN are not warranted.

4.3.6.3. Grid Reliability Projects

TURN recommends that the Commission not approve funding for the Cerritos Channel Transmission Line Relocation Project (CCTLRP) because in TURN's view it is unlikely to be timely completed and because TURN believes that the City of Long Beach should have to pay for the project.[125]

SCE explained how the project was on an expedited path to completion, and how the existing Long Beach Harbor Service and Operations Contract (approved by the Commission) governs the contractual relationship between the two entities.[126] That contract provides: "The City shall not be responsible for the cost of additions to, modifications of or removal of existing Facilities or equipment if such Facilities or equipment have been completed and in place for a length of time in excess of ten (10) years, in which case all costs shall be borne by Edison …"[127] Accordingly, TURN's proposal should be rejected.

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[123] SCE, Takayesu, Tr. 11/1415.
[124] SCE, Takayesu, Tr. 11/1418-1419
[125] Exhibit TURN-06, pp. 30-31.
[126] Exhibit SCE-18, Volume 3, p. 29.
[127] Contract Section 10.c as cited in Exhibit SCE-18, Volume 3, p. 29.

4.3.6.4. PV Dependability and Capacity-Driven Capital Expenditures

SEIA-Vote Solar recommends that the Commission not allow SCE to recover any capacity-driven capital expenditures in this rate case cycle – some $875 million of proposed spend -- until it completely reruns its System Planning analysis using a different "PV dependability curve." A PV dependability curve represents the amount of solar generation resources that a circuit can reliably depend on: theoretically, the more reliable the solar resources are to provide generation and offset other load, the more likely it is that the utility can defer utility capacity-driven upgrades. The crucial inquiry, however, is how dependable the PV generation is on a circuit or peak load days,[128] what time of the day the circuit peaks compared to when PV peaks, and where the PV generation output is on the system.[129] Utility capacity-driven projects are location-specific, and cannot be designed based on averages.[130]

SEIA-Vote Solar recommends the Commission reject SCE's 19% PV dependability curve, because it is alleged to be too low. But SEIA-Vote Solar does not offer an alternative recommended PV dependability curve.[131] SEIA-Vote Solar did not evaluate actual peak load days on a circuit-specific basis,[132] or even perform an analysis on what the weather was like on the 10 days it picked from seven years ago to simulate peak load conditions.[133] And SEIA-Vote Solar did not perform its own, location-specific analysis for capacity-driven projects.[134]

Instead, SEIA-Vote Solar recommends that SCE "re-run" its analysis with some undefined new PV dependability curve, even while acknowledging that re-analysis could result in a higher revenue requirement because of load growth in the interim.[135] Nor did SEIA-Vote Solar conduct any analysis of what that new revenue requirement would likely be.[136] On the other hand, SCE's desktop analysis (provided in rebuttal testimony) indicated that the projects needed would not likely be materially different, whether one used a 50% PV dependability curve (as SEIA-Vote Solar has hinted at but does not explicitly endorse), or a 28% PV dependability curve (as SCE has determined it will use going

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[128] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2855-56.
[129] Exhibit SCE-18, Vol. 3, p. 38.
[130] *Id.*
[131] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2859-60.
[132] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2866-67.
[133] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2867-68.
[134] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2860.
[135] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2861-2.
[136] Volkmann, SEIA-Vote Solar, Evidentiary Hearing Tr. 20: 2862.

forward on an average basis for system planning purposes).[137] The Commission should reject SEIA-Vote Solar's punitive $875 million disallowance request as unsupported, unjustified, and unrealistic for System Planning and GRC ratemaking purposes.

4.4. Distribution Maintenance and Inspection

4.5. Distribution Construction & Maintenance

4.5.1. Capital

No party takes issue with SCE's 2017-2018 forecast of $336.2 million for distribution construction maintenance capital expenditures. It is well-supported by the record, important for the basic operation and maintenance of SCE's electrical system, and the Commission should approve it.[138]

4.5.2. O&M

ORA proposes to reduce SCE's 2018 test year expense forecast in three specific O&M accounts – Distribution Storm O&M,[139] Service Guarantees #2 and #3,[140] and Streetlight Operations and Maintenance.[141] ORA's proposed reductions are unjustified and should be rejected.

For Distribution Storm O&M, ORA proposes a reduction in SCE's forecast from $9.388 million to $7.814 million and proposes to implement a one-way balancing account. Neither proposal is warranted. ORA's forecast reduction is based on using 2012-2016 instead of 2011-2015 recorded data. SCE's rebuttal testimony demonstrated how this results-oriented proposal is inconsistent with ORA's proposals to use 2011-2015 data for almost identical O&M accounts for Substation and Transmission storm expenses.[142] The Commission should not pick and choose between forecasting methodologies based on arbitrary (or nonexistent) distinctions between such accounts. SCE also explained that the use of a one-way balancing account – where shareholders would be solely responsible for storm repair-related expenses driven by weather or natural events incurred above forecast amounts – is inconsistent with cost-of-service ratemaking principles.[143] During cross-examination, ORA witness Tamara Godfrey

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[137] Exhibit SCE-18, Vol. 3, pp. 39-40. *See also* Exhibit SCE-18, Vol. 3, Appendix D.
[138] *See* Table I-1, Exhibit SCE-18, Vol. 5, p.1; *see generally* Exhibit SCE-02, Vol. 5.
[139] *See* Exhibit ORA-07, pp. 17-18.
[140] *See* Exhibit ORA-07, pp. 15-17.
[141] *See* Exhibit ORA-07, p. 13.
[142] *See* Exhibit SCE-18, Vol. 5, p. 4.
[143] *See* Exhibit SCE-18, Vol. 5, p. 4.

confirmed: that SCE's 2016 recorded costs are actually higher than SCE's 2018 TY forecast;[144] that SCE would still have a utility obligation to restore service after storms even if spending has exceeded authorized levels;[145] and that the Commission rejected this same proposal by ORA in SCE's 2015 GRC.[146]

For Service Guarantees #2 and #3, ORA recommends that Commission assign all of the costs of these credits to shareholders.[147] SCE acknowledges that this is the Commission's historical practice, but continues to maintain that it is contrary to cost-of-service ratemaking principles. SCE explained that it is more cost effective to pay out certain levels of Service Guarantee credits to customers rather than have additional crews stand by in each urban district in order to completely eliminate such payments.[148] The payment credits are a legitimate utility cost of service, and they should be paid for by customers like other such costs of service.

For Street Lighting Operations and Maintenance, ORA recommends a Test Year O&M reduction from $6.936 million to $4.543 million. SCE's rebuttal testimony demonstrated ORA's request appears to be based simply on a mistaken reading of SCE's streetlight model (which produces the forecast), by omitting one of the four legitimate categories of costs from the calculation.[149] After correcting for ORA's calculation error, SCE's forecast should be adopted.

4.6. T&D - Substation Construction & Maintenance

4.6.1. O&M

No party takes issue with SCE's 2018 O&M test year forecast of $78 million for Substation Construction & Maintenance activities described in Exhibit SCE-02, Vol. 6,[150] which should be approved by the Commission.

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144 ORA, Godfrey, Tr. 19: 2778.
145 ORA, Godfrey, Tr. 19: 2780.
146 ORA, Godfrey, Tr. 19: 2780-81.
147 *See* Exhibit ORA-07, pp. 15-17.
148 *See* Exhibit SCE-18, Vol. 5, p. 6.
149 *See* Exhibit SCE-18, Vol. 5, p. 8.
150 *See* Table I-1, p. 2, of Exhibit SCE-02, Vol. 6.

4.6.2. Capital

In SCE's direct testimony, SCE presented its 2016-2020 capital forecast (CPUC jurisdictional) of $590 million, of which $83.7 million, $92.3 million, and $136.5 million are forecast for 2016, 2017, and 2018, respectively.[151] As indicated in SCE's rebuttal testimony, SCE made the following changes to its forecast:

- SCE agrees with ORA[152] to use 2016 recorded costs (as opposed to 2016 forecast cost) for T&D Substation Construction & Maintenance capital expenditures.[153]
- In alignment with the testimonies of ORA, TURN, and SEIA-Vote Solar,[154] SCE is no longer seeking costs for the Subtransmission Relay Upgrade in 2018-2020.[155]

The two remaining capital issues are discussed below.

4.6.2.1. Substation Physical Security

Suspicious activity, trespassing, vandalism, and theft (primarily copper theft) at SCE's substations present significant safety and reliability risks that SCE seeks to address by increasing a substation's physical security through measures such as upgrading or replacing lighting and fencing.[156] Suspicious activity, trespassing, and vandalism have increased at SCE's substations from 2012-2016,[157] and, while general thefts have declined from 2014-2016,[158] SCE expects copper thefts to increase given the rise in copper prices by 28% from January 2016 to April 2017.[159] Moreover, SCE's proposed physical security enhancements not only seek to prevent copper thefts, but also to minimize the threat of trespassing, general thefts, and other suspicious activity, all of which could be precursors for future copper theft.[160] SCE treats all security incidents with equal importance because of the potential safety and reliability risk outcomes.

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151 *See* Table I-3, p. 2, of Exhibit SCE-02, Vol. 6.
152 *See* Exhibit ORA-11, p. 4, lines 24-26.
153 *See* Table I-2, p. 3, of Exhibit SCE-18, Vol. 6.
154 *See* Exhibit ORA-11, Table 11-11, p. 16, Exhibit TURN-06, pp. 41-44, and Exhibit SEIA-Vote Solar-01, p. 15.
155 *See* Table I-2, p. 3, and pp. 17-19 of Exhibit SCE-18, Vol. 6. *See* also Exhibit SCE-02, Vol. 6, pp. 32-37.
156 Exhibit SCE-02, Vol. 6, pp. 42-46; Exhibit SCE-18, Vol. 6, pp. 4-10.
157 *See* Table I-4, p. 6, of Exhibit SCE-18, Vol. 6.
158 *Id.*
159 Exhibit SCE-18, Vol. 6, p. 9.
160 Exhibit SCE-18, Vol. 6, pp. 5, 6.

The average cost for substation fencing/gate/lighting upgrades is approximately $1.0 million per site.[161] Based on factors such as public and employee safety risks and the history of theft at substations, SCE has recorded and planned expenditures for physical security enhancements in approximately 24 facilities based on need in years 2015-2017[162] and proposes to upgrade eight substation projects per year from 2016-2020.[163] In contrast, ORA proposes that SCE be allowed to upgrade only five substations per year in 2017-2018 based on ORA's arbitrary decision that only those substations that experienced four thefts have a "high frequency" of incidents.[164]

ORA's proposal to limit the 2017-2018 substation upgrades to the ten substations that experienced four or more copper thefts is illogical. SCE does not agree with ORA's arbitrary threshold of four incidents, and ORA offers no explanation as to its merits either.[165] As indicated in its testimony, when SCE queried the same data as ORA but changed the threshold number of incidents from four to three, then the number of substations that have a "high frequency" of incidents increased to 27.[166] Depending on the circumstances, it would not be safe or prudent for SCE to wait until a substation experiences four copper thefts before SCE makes upgrades, as ORA proposes.[167] As such, ORA's proposal should also be rejected because it leaves too many sites vulnerable, thus placing SCE employees and members of the public at risk.

4.6.2.2. Substation Protection & Control Replacement Program – SAS Infrastructure Replacement

Through SCE's substation protection and control replacement program, SCE identifies and replaces protection and control equipment approaching the end of its service life, that contain

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[161] Exhibit ORA-11, p. 14 (citing to SCE's response to ORA-SCE-207-YNL, Q.2.d).
[162] Exhibit SCE-02, Vol. 6, pp. 42-43, 46.
[163] Exhibit SCE-02, Vol. 6, p. 46. *See* Table I-17 on p. 46, which shows the nominal costs of the enhancements for the eight substations/year to be approximately $1 million/substation.
[164] Under ORA's analysis, 11 substation sites have experienced four or more incidents during the 2013-2016 time period, however, since SCE has already performed upgrades at one of these 11 substations, ORA's proposal is essentially to permit physical security upgrades at the remaining 10 substation sites during 2017-2018. Exhibit SCE-18, Vol. 6, pp. 7-9; Exhibit ORA-11, pp. 14-15.
[165] Exhibit SCE-18, Vol. 6, p. 8.
[166] Exhibit SCE-18, Vol. 6, p. 8.
[167] SCE, Flores, Tr. 9/1174-1175.

components known to be problematic or no longer available, or that can no longer be cost-effectively maintained.[168] SCE's 2018 capital forecast for this program is $55.7 million.[169]

Generally speaking, this program involves four sub-programs, one of which is the SAS Infrastructure Replacement program and which is contested by TURN.[170] SCE's SAS Infrastructure Replacement program, which is the subject of SCE's request in Exhibit SCE-02, Volume 6, is different than the Grid Modernization SA-3 Program, which is the subject of Exhibit SCE-02, Volume 10.[171] The SAS Infrastructure Replacement program involves the replacement of aging SA-1 equipment with SA-3 equipment at 65 locations,[172] while the Grid Modernization SA-3 Program involves the replacement of SA-1 equipment at different substations with SA-3 equipment and also involves the installation of Grid Modernization equipment such as the Common Substation Platform (CSP) and Mechanical Electrical Equipment Room (MEER) buildings.[173]

TURN, however, appears to think the two programs are the same. TURN's witness in this area incorrectly states, with respect to the SAS Infrastructure Replacement Program, that "All the Company's justifications are actually presented in Volume 10 (Grid Modernization) technology, although I address them here as the proposed technology is the same."[174] TURN's misunderstanding is also apparent in its Table 6 of Exhibit TURN-06, where TURN proposes to eliminate the entire SAS Infrastructure Forecast in exchange for funding to implement CSP at 22 substations in 2018, resulting in a $13.4 million reduction to SCE's 2018 capital forecast.[175] CSP, however, relates to the Grid Modernization SA-3 program and not the SAS Infrastructure Replacement Program.[176]

While SCE's Grid Modernization SA-3 program addresses some infrastructure replacement needs, it is also designed to address issues caused by higher penetrations of DERs.[177] This differs from

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[168] Exhibit SCE-02, Vol. 6, p. 30.
[169] *See* Exhibit SCE-18, Vol. 6, Table I-2, p. 3.
[170] The other three sub-programs are (1) Non-Bulk Relay Replacement – 115kV & Below; (2) Bulk Relay Replacement – 220kV & 500 kV; and (3) Digital Fault Recorders Replacement. *See* Table I-5 in Exhibit SCE-18, Vol. 6, p. 12.
[171] Exhibit SCE-18, Vol. 6, pp. 12, 14-15.
[172] *See* Table I-13 in Exhibit SCE-02, Vol. 6, p. 32.
[173] Exhibit SCE-18, Vol. 6, pp. 15-16.
[174] Exhibit TURN-06, p. 46.
[175] *See* Table 6 in Exhibit TURN-06, p. 49. TURN appears to propose to eliminate the SAS Infrastructure Replacement for all 65 substations at a cost of $53.8 million and replacing it with CSP over the 2016-18 period. *Id.*
[176] Exhibit SCE-18, Vol. 6, p. 15.
[177] Exhibit SCE-18, Vol. 6A, p. 12.

the SAS Infrastructure Replacement Program, which is designed to address equipment failure and obsolescence only, as discussed in more detail below:[178]

- The SA-1 relays have a high failure rate.
- Computer-based components require more frequent upgrade or replacement.
- Almost half of the existing protection and control systems on SCE's system are no longer supported by the manufacturer.
- Most protection and control systems have no cost effective hardware/software upgrade solution.
- Vendors no longer support the software for the operator interface.
- There is a depletion of Distribution Protection Units/Transmission Protection Unit (DPU/TPU) spare parts inventory.
- The DPU/TPU relay failure rate is expected to increase to 20.4% by 2025 as technology ages.

SCE proposes that aging SA-1 equipment be replaced with SA-3 equipment, which is the most viable and cost effective replacement option. As explained in SCE witness Marc Flores' testimony:[179]

- SA-3 uses an open standards design that is compatible with multiple vendors and is scalable and adaptable to new technologies.
- SA-3 provides a standardized way for manufacturers to allow their products to interact with other devices.
- SA-3 helps SCE meet its current technology requirements, rather than using a non-cost-effective piece meal approach.
- SA-3 can be used and incorporated into future automation needs.

The record is not clear if TURN believes that the entire SAS Infrastructure Program should be eliminated in favor of CSP, as indicated in TURN's testimony on the SAS Infrastructure Replacement program,[180] or with something else such as SA-2, as TURN suggests for Grid Modernization substation automation.[181] Regardless, TURN's proposal should be rejected because SCE needs to replace substation and control replacement equipment that is at its end of service life, and SA-3 is the superior and preferred option.

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[178] Exhibit SCE-18, Vol. 6, pp. 14-15.
[179] Exhibit SCE-18, Vol. 6, p. 16.
[180] Exhibit TURN-06, p. 49.
[181] Exhibit TURN-06, p. 51.

4.7. T&D – Transmission Construction & Maintenance

Based on the evidentiary record, SCE respectfully requests that the CPUC approve SCE's 2018 O&M forecast of $40.920 million[182] for Transmission Construction & Maintenance activities described in Exhibit SCE-02, Vol. 7. Below, SCE addresses the two O&M issues raised by ORA: (a) Transmission Overhead and Underground Line Maintenance, and (b) Transmission Vegetation Management.

In Exhibit SCE-02, Vol. 7, SCE also presented its 2016-2020 capital forecast (CPUC jurisdictional, nominal $) of $313 million, which SCE also requests that the CPUC adopt.[183] Below, SCE addresses the single issue raised by ORA on SCE's capital forecast, specifically, Transmission Tools and Work Equipment.

4.7.1. O&M: Transmission Overhead and Underground Line Maintenance

Overhead and underground line maintenance includes performing repairs on transmission line equipment and structures, such as poles, towers, and conductors.[184] SCE's 2018 forecast of $6.841 million is based on the last recorded year (2015) since (1) 2011-2013 recorded costs are not representative of 2018 costs due to the accounting change in overhead divisions starting in 2014,[185] and (2) 2014 recorded costs are also not representative because SCE performed significant programmatic maintenance activities (such as tower painting, torqueing, etc.) that SCE does not anticipate performing at the 2014 level going forward.[186]

ORA also agrees that 2014 costs are not representative of test year expenses, but proposes using a four-year average (2011-2013 and 2015), thus decreasing SCE's 2018 forecast to $5.786 million.[187] While ORA explains in its testimony why 2014 is not representative of test year expenses (with which SCE agrees), ORA does not explain why 2011-2013 should be included in the average despite

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[182] In SCE's direct testimony in Exhibit SCE-02, Vol. 7, p. 2, SCE's 2018 O&M forecast was $41.023 million, which was lowered to $40.920 million in Exhibit SCE-02, Vol. 7A. *See* Table I-1 in Exhibit SCE-02, Vol. 7A, p. 2.

[183] *See* Table I-3, Exhibit SCE-02, Vol. 7, p. 2. Based on ORA's recommendation, SCE has agreed to use its 2016 recorded in place of SCE's 2016 forecast. *See* Exhibit ORA-11, p. 4, lines 24-26.

[184] Exhibit SCE-02, Vol. 7, p. 14.

[185] Exhibit SCE-02, Vol. 7, p. 15. As indicated in footnote 20 on page 15, details on the accounting change can be found in SCE-08, Vol. 3, and SCE's response to MDR Question I.A.12. *See* also Exhibit SCE-18, Vol. 7, pp. 5-6.

[186] Exhibit SCE-02, Vol. 7, p. 15. As indicated in footnote 20 on page 15, details on the accounting change can be found in SCE-08, Vol. 3, and SCE's response to MDR Question I.A.12.

[187] Exhibit ORA-06, pp. 12-14.

documented changes in accounting, except for a conclusory statement that a four-year average is a "reasonable approach."[188] ORA also states that "Non-labor expenses recorded in last year recorded 2015 [of $2.358 million] are comparable to years 2011-2013" but this is inconsistent with the recorded data which shows that recorded costs for 2012 and 2013 were $1.5 million and $1.8 million, respectively.[189]

Given that the recorded costs in 2011-2013 are not indicative or directly comparable to expenses recording to this activity today due to the accounting change in division overheads starting in 2014, the Commission should reject ORA's proposal to include 2011-2013 in an average and instead adopt 2015 as the basis for forecasting 2018 test year O&M expenses.

4.7.2. O&M: Transmission Vegetation Management

Transmission Vegetation Management includes expenses associated with tree trimming, tree removal, weed abatement, and tree planting.[190] Expenses were relatively stable from 2011-2013, but increased by approximately 10% in 2014 and then again by about 20% in 2015 due to a change in the vegetation management contract starting in May 2014.[191] Given the work expected in the Test Year and the new vendor contract term implemented in May 2014, SCE selected the last recorded year (2015) as the basis for SCE's 2018 O&M forecast of $10.442 million.[192] In contrast, ORA proposes that SCE use a two-year average (2014-2015) due to the recent changes in the contractor terms, thus reducing SCE's forecast to $9.474 million.[193]

As indicated by SCE witness Anthony Edeson, 2014 recorded costs are not representative of 2018 test year expenses since 2014 costs do not represent a full year of expenses under the new contract terms.[194] SCE informed ORA of the May 2014 contract in SCE's response to an October 2016 data request.[195] As such, the CPUC should adopt SCE's 2018 O&M forecast of $10.442 million since 2015

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[188] Exhibit ORA-06, p. 13.
[189] *See* Table 6-13 on page 13 of Exhibit ORA-06.
[190] Exhibit SCE-02, Vol. 7, p. 24.
[191] *See* pp. A-3, 6-7 of Exhibit SCE-18, Vol. 7.
[192] Exhibit SCE-02, Vol. 7, p. 25; Exhibit SCE-18, Vol. 7, pp. 7-8.
[193] Exhibit ORA-06, pp. 14-16.
[194] Exhibit SCE-18, Vol. 7, p. 8.
[195] *See* SCE's response to Question 1 of ORA-SCE-EXAM-006-JML, dated October 12, 2016, which indicates that the new contract went into effect in May 2014, and which is attached as page A-3 to Exhibit SCE-18, Vol. 7.

recorded costs reflect SCE's Transmission Vegetation Management ongoing expenses under the contract's latest terms.

4.7.3. Capital: Transmission Tools and Work Equipment

Transmission Tools and Work Equipment include the costs for acquiring and retiring portable tools and work equipment that cost more than $1,000, such as electric generators, cable pulling equipment, gas monitors, air compressors, etc.[196] SCE's 2016 forecast for Transmission Tools and Work Equipment is $1.9 million and gradually increases to $2 million in 2020.[197]

ORA and SCE agree on the 2016 and 2018 forecast. For 2016, ORA proposes that the CPUC adopt SCE's 2016 recorded as the 2016 forecast.[198] SCE agrees with this change, and thus agrees to a revised 2016 forecast of $1.274 million forecast, which is a $616,000 reduction.[199] For 2018, ORA agrees with SCE's forecast of $1.953 million.[200]

For 2017, ORA disagrees with SCE's forecast of $1.917 million for Transmission Tools and Work Equipment. ORA's 2017 forecast is $1.397 million, which is approximately 70% of SCE's 2015 recorded cost of $1.924 million[201] because SCE reduced its 2017 forecast for Transmission Planned Capital Maintenance to 70% due to resource constraints.[202] However, as indicated by SCE witness Anthony Edeson, there is no singular correlation between SCE's Transmission Tools and Work Equipment and the Transmission Planned Capital Maintenance. As a threshold matter, Transmission Tools and Work Equipment are used in <u>all</u> parts of transmission construction and maintenance activities presented in Exhibit SCE-02, Volume 7, and not just Transmission Planned Capital Maintenance.[203] Transmission construction and maintenance work includes a wide variety of activities such as construction on breakdown maintenance, inspections, and transmission line rating remediation projects,[204] and SCE forecasts an overall increase in 2016-2018 for transmission construction and

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[196] Exhibit SCE-02, Vol. 7, p. 33.
[197] Table I-3 in Exhibit SCE-02, Vol. 7, p. 2, and Figure IV-11 in Exhibit SCE-02, Vol. 7, p. 34. Please note that in SCE's rebuttal testimony, SCE proposes to adopt 2016 recorded for its 2016 forecast. *See* Table I-2 in Exhibit SCE-18, Vol. 7, p. 3.
[198] Exhibit ORA-11, p. 20.
[199] *See* Table I-2 and Table I-5 in Exhibit SCE-18, Vol. 7, pp. 3, 9; Table 11-12 in Exhibit ORA-11, p. 20.
[200] *See* Table 11-12, Exhibit ORA-11, p. 20.
[201] *See* Table 11-12, Exhibit ORA-11, p. 20 and Table 1-5, Exhibit SCE-18, Vol. 7, p. 9.
[202] Exhibit ORA-11, pp. 19-20.
[203] Exhibit SCE-18, Vol. 7, pp. 10-11.
[204] SCE, Edeson, Tr. 13/1778.

maintenance work.[205] Moreover, looking solely at Transmission Planned Capital Maintenance, the correlation between this activity and Transmission Tools and Work Equipment would be a moderate 0.51, which is far from the value needed to show a strong correlation, which is 1 or close to 1.[206]

Given that transmission tools and work equipment are used to support all activities in transmission construction and maintenance, and not just Transmission Planned Capital Maintenance, and there is not a strong correlations between Transmission Tools and Work Equipment and Transmission Planned Capital Maintenance, the CPUC should reject ORA's proposed reduction to SCE's 2017 forecast.

4.8. Infrastructure Replacement

SCE's opening and rebuttal testimony demonstrated that large parts of its substation and distribution infrastructure are beyond their useful service lives, and also explained why it is preferable to proactively replace that aging structure before it fails in place.[207] Several of the programs at issue in these volumes of testimony lie at the heart of the utility's basic safety and reliability service obligations. Overall, SCE's proposed 2017-2018 capital expenditures in the 11 Infrastructure Replacement programs total $971.584 million.[208] ORA recommends reductions totaling $68.803 million, while TURN recommends reductions totaling $185.557 million, and CFC recommends reductions totaling $23.214 million. The Commission should reject those recommended reductions, as explained in detail below.

4.8.1. Worst Circuit Rehabilitation Program (WCR)

SCE's WCR program proactively eliminates aging mainline cable on SCE's worst-performing circuits to help improve system reliability. TURN proposes reducing the WCR forecast by $19.345 million in 2017 and 2018, based on its argument that SCE's reliability modeling forecast may be flawed. TURN also recommends that SCE begin recording cable failures by cable type, urges the Commission to change the minimum age injection on mainline cable, and posits that SCE should begin piloting cable injections (instead of replacements) on mainline cable. SCE's rebuttal testimony demonstrated that the assumptions it uses in its model do not bias the results; all models must make assumptions.[209] Perhaps

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[205] Exhibit SCE-18, Vol. 7, p. 11, lines 4-8.
[206] *See* Exhibit SCE-18, Vol. 7, pp. 11-12. *See* Table I-6 on page 12, which shows a correlation of 0.50912.
[207] *See* Exhibits SCE-02, Vol. 8 and SCE-18, Volume 8.
[208] *See* Exhibit SCE-18, Volume 8 at p. 2, Table I-1.
[209] *See* Exhibit SCE-18, Volume 8 at p. 4.

most importantly, SCE has validated the reasonableness of its assumptions by comparing the assumptions with actual results. That validation effort demonstrated that there was less than a 1% difference between the assumed results and actual results.[210] SCE also showed how isolating the effects of aging cable (as opposed to conflating those effects with other programs that have potential reliability impacts) is appropriate, especially in light of TURN's and other parties' proposed reductions to programs such as Grid Modernization.[211] SCE respectfully urges the Commission not to precipitously order a mainline injection cable testing program, but rather to proceed with a cost-benefit analysis before potentially implementing such a program.[212] There are real differences between radial cable and mainline cable in the way they are designed and constructed, and those differences have real potential consequences should mainline cable injection testing not prove cost-effective.[213]

Finally, regarding SCE's proposed level of mainline cable replacements, it is important to note that SCE is remediating the least-reliable circuits, where our customers' reliability is the worst (and declining). Finally, as SCE witness Joe Goizueta confirmed during evidentiary hearings, SCE needs to replace 350 miles of mainline cable per year (which is SCE's request), just to maintain existing reliability levels.[214] The Commission should grant SCE's crucial reliability-related request in this area.

4.8.2. Overhead Conductor Program (OCP)

SCE's OCP is a crucial safety-related program designed to reduce the number and frequency of "wire down" events by executing both proactive and reactive conductor work to ameliorate the effects of what is known as "small wire."[215] ORA, TURN, and CFC all recommend draconian cuts to the program (2017-2018 capital expenditure reductions of $68.815 million, $127.296 million, and $23.214 million, respectively) for various unconvincing reasons.

ORA recommends that SCE replace only 200 circuit-miles in 2017 and 250 circuit-miles in 2018, which is lower than SCE's forecast by 100 and 50 circuit-miles, respectively.[216] ORA's argument is based on two fundamental flaws. First, ORA recommends a lower amount of OCP work because it

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[210] *See* Exhibit SCE-18, Volume 8 at p. 5.
[211] *See* Exhibit SCE-18, Volume 8 at pp. 5-6.
[212] *See* Exhibit SCE-18, Volume 8 at pp. 6-7.
[213] TURN, Jones, Tr. 21: 3006.
[214] SCE, Goizueta, Tr. 13: 1839.
[215] SCE Exhibit SCE-18, Volume 8 at p. 7.
[216] Exhibit ORA-08, p. 21.

claims other cable-related replacements have materially increased in recent years. Therefore, ORA reasons that all of the OCP work is not necessary for reliability improvements. But SCE demonstrated clearly that OCP is primarily safety-related, not reliability related.[217] As Mr. Goizueta testified during the evidentiary hearings:

> Q: What is overwhelmingly the biggest contributor to [the] risk factor [of downed overheard wire], just looking at that number?
> A: Human contact with conductor.
> Q: What happens when humans come in contact with conductors?
> A: They're likely to become electrocuted.[218]

Second, ORA's claims that SCE's increased OCP workload is "uncommon" are unavailing. While SCE may be proposing to do more work on this critical, safety-related program than it has done in the past, that is unsurprising given that OCP is a new program and because SCE's proposed increase in mitigated conductor-miles represents less than 1% of its entire inventory of overhead conductor.[219] SCE also demonstrated that it could effectively "ramp up" for the proposed work in a cost-effective fashion.[220]

TURN's arguments for large reductions in SCE's scope of work are also misplaced,[221] and are based on a misunderstanding of purported differences between "reactive" and "proactive" projects, a factually-inaccurate characterization of what are known as oversized branch line fuses (BLFs), and an unjustified reliance on other potential mitigation solutions. First, SCE's rebuttal testimony demonstrated that TURN's attempted distinction between "proactive" and "reactive" projects is essentially meaningless, both because the two kinds of projects have similar unit costs and because all projects are "reacting" to historical wire down events.[222] Second, TURN's claims that SCE's shareholders should incur a 10% penalty due to "self-inflicted damage" from oversized BLFs are similarly misplaced. While SCE acknowledges that its understanding of the sizing of BLFs has evolved over time, SCE also demonstrated that oversized BLFs are better for the system than no BLFs at all.[223] In other words, SCE

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[217] Exhibit SCE-18, Volume 8 at pp. 9-10.
[218] SCE, Goizueta, Tr. 13:1834.
[219] *See* Exhibit SCE-18, Volume 8, pp. 11-12.
[220] *See* Exhibit SCE-18, Volume 8, pp. 12-13.
[221] SCE's response to TURN's argument that lower cost mitigation options should be adopted based on SCE's risk-informed decision-making program is addressed in section 4.2.1 of this Opening Brief.
[222] *See* Exhibit SCE-18, Volume 8, pp. 14-15.
[223] *See* Exhibit SCE-18, Volume 8, p. 16.

did not "self-inflict" "damage" on the system by installing the older BLFs, which actually provided aggregate system benefits. There is no justification for fining SCE's shareholders for those actions. Third, as Mr. Goizueta testified, given the scope of the problem (16,000 miles of small wire overhead conductor) and the crucial public safety issues, that although SCE will keep evaluating risk mitigation alternatives, it is prudent to ramp up OCP now instead of waiting for potential alternative solutions.[224]

CFC's proposed reductions in SCE's capital expenditures for OCP should also be rejected. Similar to ORA's arguments, CFC incorrectly characterizes the safety-related OCP program by focusing on reliability.[225] SCE also demonstrated that it is the industry's new understanding of existing safety risk from small wire that is driving the OCP.[226]

4.8.3. Capacitor Bank Replacement Program

SCE's Capacitor Bank Replacement Program replaces failed and obsolete capacitor banks, which are important for maintaining adequate voltage levels on the system.[227] SCE's original forecast was $34.744 million in capital expenditures over 2017-2018 based on a forecast annual replacement volume higher than the historical five-year average, but significantly lower than the steady state replacement rate; TURN proposed $18.274 million based on reduced unit costs and work scope.[228] SCE agreed to accept TURN's proposal to use 2014 unit costs, which reduces SCE's forecast to $27.692 million.[229] But reducing the volume of replacements will not allow SCE to get closer to a long-term steady state rate of replacements of capacitor banks. [230]

4.9. T&D – Poles

SCE's testimony supported forecasts for its various pole-related activities (Deteriorated Pole Program, the Pole Loading Program (PLP), the Joint Pole Organization, and other items such as joint pole credits and wood pole disposal) of $43.558 million in O&M expenses (2015 $) for the 2018 Test Year, and $317.992 million (nominal $) in capital expenditures.[231] SCE's pole programs address major

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[224] SCE, Goizueta, Tr. 13: 1812-33.
[225] *See* Exhibit SCE-18, Volume 8, pp. 17-18.
[226] *See* Exhibit SCE-18, Volume 8, p. 19; *see also* SCE, Goizueta, Tr. 13: 1817.
[227] *See* Exhibit SCE-18, Volume 8, p. 19.
[228] *See* Exhibit SCE-18, Volume 8, p. 20.
[229] *See* Exhibit SCE-18, Volume 8, p. 21.
[230] *See* Exhibit SCE-18, Volume 8, p. 20.
[231] *See* Exhibit SCE-02, Volume 9.

safety and reliability risks and the compliance requirements of General Order 165 (GO 165) and General Order 95 (GO 95). The forecasts SCE presented are primarily driven by these regulatory requirements and are based on the amount of work required to comply with these rules and enhance the safety and reliability of the grid.[232] ORA and TURN proposed various reductions to some of these various O&M[233] and capital forecasts.[234] SCE responds to those arguments below.

4.9.1. O&M expenses

Expenses associated with pole programs record in four GRC accounts: 566.125, 571.125, 583.125, and 593.125. ORA proposed reductions to portions of accounts 566.125, 583.125, and 593.125 totaling $9.6 million for the 2018 Test Year forecast. Impacted activities include Transmission Pole Loading Program Assessments, Distribution Pole Loading Program Assessments, Joint Pole Organization Expenses, and Distribution Pole Loading Program Repairs. ORA did not contest SCE's forecasts for Transmission and Distribution Deteriorated Pole Inspections, Transmission and Distribution Pole Loading Program Related Expense, Joint Pole O&M Credits, or Transmission Pole Loading Program Repairs.

TURN proposes reductions to portions of accounts 566.125, 571.125, 583.125, and 593.125 of $3.859 million in total for the 2018 Test Year forecast. Impacted activities include Transmission Pole Loading Program Assessments, Transmission Pole Loading Program Repairs, Distribution Pole Loading Program Assessments, and Distribution Pole Loading Program Repairs. TURN does not contest SCE forecasts for Transmission and Distribution Deteriorated Pole Inspections, Transmission and Distribution Pole Loading Program Related Expense, Joint Pole Organization, or Joint Pole O&M Credits.

ORA's and TURN's proposed reductions to O&M expense forecast for PLP assessments are unjustified. In D.15-11-021, the Commission rejected ORA's proposal to lengthen the PLP Assessment program from seven to ten years. In adopting a seven-year assessment schedule in SCE's 2015 GRC decision, the Commission stated "We find that the public interest in quickly developing a more comprehensive understanding of the extent of overloaded poles outweighs the potential cost deferral

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[232] *See* Exhibit SCE-18, Volume 9, p. 1.
[233] *See* Exhibit SCE-18, Volume 9, p. 3, Table I-1.
[234] *See* Exhibit SCE-18, Volume 9, p. 4, Table I-2.

advantage of slowing the pace of assessments."[235] SCE's forecast is consistent with completing assessments in 2021,[236] just over the proposed seven-year timeframe starting at the beginning of 2014. ORA's proposed level of funding is inconsistent with the seven-year timeframe. ORA does not dispute SCE's unit cost per assessment, or the forecast rate at which assessments will be performed; therefore it implicitly requests a reduction in the volume of assessments to be funded. ORA's proposed reductions would only fund 175,824 assessments per year, a significant reduction from SCE's proposed 230,000 assessments per year.[237] ORA's proposal will result in SCE performing 54,176 fewer assessments per year, thereby extending SCE's assessment cycle to a full nine years.[238]

TURN's reduced O&M forecast for this subaccount seemingly resulted from an erroneous unit cost number provided by SCE and subsequently corrected through an errata. Furthermore, SCE recently conducted a solicitation for assessments and found that our forecast contract costs (which are the primary O&M cost drivers of the PLP program) are competitive.[239]

ORA recommends reducing Joint Pole Organization O&M expensess by approximately $1.106 million. ORA's reduction should be rejected. ORA offered no explanation of why reducing SCE's requested increase for 2018 by two-thirds is reasonable or consistent with ORA's ostensible agreement with SCE's need to add staffing.[240]

For Transmission and Distribution Pole Loading Program Repairs, TURN has recommended a reduction of approximately $1.374 million, and ORA has recommended a reduction of approximately $2.745 million. As detailed in SCE's rebuttal testimony, SCE has revised its unit cost numbers and therefore reduced its forecast accordingly.[241] But even when these lower rates are applied, ORA's proposal would not provide sufficient funding to complete needed repairs. In 2018, the difference between forecast repair volume and ORA's implied repair volume would reach 824 and the cumulative

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[235] D.15-11-021, p. 123.
[236] CUE-SCE-001, Q. 61.a and 61.b on Appendix B, p. B-12.
[237] Exhibit SCE-18, Volume 9, p. 8.
[238] Exhibit SCE-18, Volume 9, p. 8. ORA's testimony also incorrectly calculates a three-year average and is inconsistent with its apparent recommendation to fully grant SCE's related capital request. *See id.* at pp. 8-9.
[239] Exhibit SCE-18, Volume 9, p. 9.
[240] ORA-07, p. 27, lines 20-21 ("ORA's estimate of $7.442 million captures SCE's increased staffing levels …").
[241] Exhibit SCE-18, Volume 9, pp. 14-15.

shortfall would increase to over 2,400 repairs by 2020.[242] SCE is on pace to complete 220,000 assessments in 2017, so a further reduction to SCE's O&M forecast as ORA requests is not warranted.[243]

4.9.2. Capital Expenditures

TURN proposes reductions to the unit cost forecast for all pole replacement activities that would result in a total reduction of $116.469 million (2015$) for these pole replacement and remediation activities.[244] TURN proposes to remove the increase in contractor cost experienced by SCE from 2012 to 2015, which is shown in Table IV-21 and Table IV-22 of SCE-02, Vol. 9, from SCE's proposed forecasts for pole replacements under the Pole Loading and Deteriorated Pole Programs. TURN does not contest SCE's proposed volumes of pole replacements for Distribution Deteriorated Pole Replacements, Transmission Deteriorated Pole Replacements, Pole Loading Program Distribution Pole Replacements, and Pole Loading Program Transmission Pole Replacements.

TURN's dramatic proposed reduction in capital costs should be rejected for three reasons: (1) TURN's testimony does not acknowledge pole unit cost savings related to Operational Excellence and thus would constitute double counting of those savings; (2) TURN's testimony does not adequately analyze the reasonableness of the increases in contract labors costs; and (3) TURN does not address steel stubbing, which is described in SCE-02, Vol. 9, p. 52. The savings from steel stubbing are incorporated in SCE's forecast here and result in a lower weighted average cost for pole remediation.[245]

First, as demonstrated in SCE's rebuttal testimony, TURN ignores the savings from procurement costs SCE has already embedded in its forecasts. By doing so, TURN is essentially advocating for a 2018 unit rate that is more than 25% below SCE's recorded distribution pole unit cost for 2015, a reduction of $3,709 per pole. This reduction exceeds the 2012-2015 increase of $1,250,[246] and the 2015-

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[242] Exhibit SCE-18, Volume 9, pp. 15-18.
[243] Exhibit SCE-18, Volume 9, p. 18.
[244] Exhibit TURN-12, p. 32-33.
[245] SCE-02, Vol. 9, p. 53, Table IV-25; SCE-02, Vol. 9, p. 54, Figure IV-7.
[246] SCE-02, Vol. 9, Table IV-21, line 8 shows a 2012 to 2015 variance of $1,250 for distribution pole replacements.

2018 increase of $638,[247] combined. The resulting effective unit cost of $11,483 in 2015 dollars[248] is well below the level resulting from D.15-11-021 of $12,913 (in 2015 dollars).[249]

Second, TURN's simplistic argument that SCE's forecast should be reduced because contract labor costs have increased faster than inflation ignores that SCE engages in a competitive bidding process in order to maximize value for the company and our customers. The bidding process entails commercial and technical analysis, in addition to negotiations to help ensure that the best value for customers is realized from awards to SCE's contractors.[250]

Third, TURN ignores the effects of steel stubbing, which reduces the weighted average cost of pole remediation and offsets a portion of the increases experienced in recorded unit costs. Table IV-25 in SCE-02, Vol. 9 shows that the forecast weighted average cost of pole remediation will drop by 10% from 2016 through 2020 for distribution poles and 5% for transmission poles, resulting in a unit cost forecast that is 3% and 7% above 2012 recorded costs for distribution and transmission poles, respectively, by 2020.[251]

4.9.3. Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA)

SCE recommends that the Commission continue the PLDPBA and reject TURN's and ORA's recommendation to keep a "cap" on the balancing account. TURN's and ORA's primary argument for "capping" the account (and in TURN's case, making it a one-way balancing account), namely that in 2015 SCE recorded costs in excess of the authorized amount, is unavailing. As explained in SCE's direct and rebuttal testimony, the variance between 2015 forecast and recorded costs was the result of a combination of factors. One, there was a much larger number of transmission poles, relative to distribution poles, as a result of changes in intrusive inspection failure rates.[252] Two, the unit costs increased relative to forecast.[253] Three, poles initially planned for 2016 and later years were accelerated

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[247] SCE-02, Vol. 9, Table IV-23, line 6 minus line 1 = $638.

[248] $15,192 (Table IV-23, SCE-02, Vol. 9, p. 51) distribution pole cost for 2018 - $3,709 = $11,483 in 2015$.

[249] D.15-11-021, p. 107, indicates a distribution pole unit rate of $11,766 in 2012$. SCE's proposed escalation index (SCE-09, Vol. 1, Chapter VII) would result in a 2015$ rate of $12,913.

[250] Exhibit SCE-18, Volume 9, p. 20.

[251] Table IV-25 in SCE-02, Vol. 9, shows a 2020 weighted average remediation cost of $13,722 and $22,218 for distribution and transmission pole replacements; Table IV-21 shows a 2012 recorded distribution unit cost of $13,304 for distribution and Table IV-22 shows a 2012 recorded transmission unit cost of $20,830. ($13,722-$13,304)/$13,304 = 3% increase; ($22,218-$20,830)/$20,830 = 7% increase.

[252] Exhibit SCE-02, Vol. 9, p. 4; Exhibit SCE-18, Vol. 9, p. 23.

[253] Exhibit SCE-18, Vol. 9, p. 23.

to 2015 for operational reasons.[254] The early replacement of these poles merely changes the timing of the expenditures from a later year to an earlier year. A cap would not eliminate these costs, it would merely shift them to later years. Moreover, significant uncertainty in forecast costs still exists given several factors, including the differences in failure rates based on geography.[255] Finally, as discussed above, SCE's unit cost increases are not unreasonable.

4.10. Grid Modernization

In SCE's Grid Modernization testimony (Exhibits SCE-02, Volume 10 and SCE-18, Volume 10), SCE showed that the current grid must evolve to maintain and improve reliability and safety while meeting changing customer expectations and environmental goals. SCE's Grid Modernization proposal rests on the fact that SCE's grid is outdated and reliability is declining. At the same time, the pace of policy change, increasing activity and complexity on the distribution grid associated with DERs, and customer demands for improved service require reliability to improve. A modern grid needs the integrated suite of distribution automation (DA), substation automation (SA-3), communications infrastructure (FAN, WAN, CSP, GMS) and analytics and planning applications (DRPEP, SMT) that SCE proposes in its Grid Modernization volume.

At its core, SCE's request focuses on achieving key capabilities of a modern distribution grid.[256] These capabilities include real-time visibility of the power flows on the distribution grid, quick operator decision-making and response times, and protection against physical and cybersecurity threats. In addition, SCE's Grid Modernization efforts will ultimately enable DER integration and adoption, and allow DERs to provide grid benefits. There is little question that DERs will continue to grow at a fast pace and that integration of DERs is needed to meet California's environmental goals, including greenhouse gas emissions reduction targets for 2030.[257] But regardless of the level of DER growth and the outcome of the Distribution Resources Plan (DRP), SCE needs these capabilities today to continue to provide safe and reliable service, meet customer demands, and keep pace with its industry peers.

Exhibit SCE-18, Vol. 10 describes ORA, SEIA-Vote Solar, and TURN's positions, which are briefly summarized here. ORA proposes no capital or O&M funding for new Grid Modernization

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[254] Exhibit SCE-18, Vol. 9, p. 23.
[255] Exhibit SCE-18, Vol. 9, p. 24.
[256] *See* Exhibit SCE-02, Vol. 10, pp. 13-17; *See also* SCE-18, Vol. 10, pp. 1-2, 9-10.
[257] *See* SCE GRC Workshop Presentation Evolving Our Grid, October 24, 2016, p. 14, in Exhibit SCE-18, Vol. 10, Appendix C, p. C-15.

programs, and limited funding for certain historical programs for this rate case period.[258] In support of these assertions, ORA asserts that DER-related Grid Modernization projects should await the results of the DRP proceeding, and that SCE should demonstrate a path toward cost-effectiveness.[259] ORA provides a critique of SCE's payback period analysis[260] and completely ignores SCE's benefit-cost analysis (BCA). ORA opposes the balance of SCE's request on two basic grounds: (1) that SCE's strategy of using Grid Modernization to improve (rather than just maintain) reliability is inappropriate; and (2) that these Grid Modernization projects must be unnecessary to maintain reliability, in that SCE has not been engaged in them in the recent past, and given SCE's current reliability performance.[261] ORA provides scant analysis of SCE's specific Grid Modernization projects, summarily rejecting them based on their association with the Grid Modernization program, which ORA conflates with DER integration and the DRP, rather than directly addressing SCE's analysis or considering each request on its merits.[262]

TURN objects to the scope of SCE's Grid Modernization proposal and recommends a scaled-down version that includes less automation,[263] an Advanced Distribution Management System (ADMS)/Distributed Energy Resources Management System (DERMS)[264] as opposed to SCE's new GMS, upgrades to SCE's existing and outdated field area network, NetComm,[265] instead of WAN and FAN, and CSP without SA-3.[266] TURN criticizes SCE's proposal as characterized by unnecessary operator automation.[267] TURN acknowledges the impact of "masked load,"[268] but implies that the problems are limited to large wholesale solar systems on certain circuits, and that the solution lies in less

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[258] *See* Exhibit ORA-09, pp. 2-4.
[259] *See* Exhibit ORA-09, p. 2.
[260] *See* Exhibit ORA-09, pp. 2, 3, 8, and 32-55.
[261] *See* Exhibit ORA-09, pp. 30-32 and 45-50.
[262] *See e.g.,* Exhibit ORA-09 p. 115 (re FAN); p. 117 (re SA-3 and CSP), p. 119 (re GMS), p. 120 (re DRPEP and SMT) (recommending "no expenditures" because these programs are "an integral part of [SCE's] Grid Modernization plan").
[263] *See* Exhibit TURN-04, pp. 41 and 62-63.
[264] *See* Exhibit TURN-04, p. 66.
[265] *See* Exhibit TURN-04, p. 51.
[266] *See* Exhibit TURN-06, pp. 82 and 85-86.
[267] *See* Exhibit TURN-06, pp. 54-65.
[268] *See* Exhibit TURN-06, p.56 ("Changes in power flow caused by DERs do cause unpredictable circuit loading during switching operations, primarily resulting from masked loads. It is also true that loads which are "masked" by generation on the distribution system present challenges to grid operators as described in the examples provided by SCE.").

expensive means of obtaining distributed generation production data.[269] TURN recognizes that the primary purpose of Grid Modernization projects is to promote reliability and DER integration, but asserts that these projects do not address safety risks.[270]

SEIA-Vote Solar generally adopts ORA's recommendations,[271] but recommends authorizing SCE to proceed with implementation of a DERMS, without implementing GMS, and "to deploy the minimum technology necessary to satisfy the new DER communication requirements of Rule 21 while fully leveraging the monitoring, communication and control capabilities inherent in most DER technologies."[272] SEIA-Vote Solar also provides specific critiques to SCE's BCA.[273]

SCE's proposal in its September 1, 2016 Application was based on an assessment that considered a number of different factors, including safety, reliability, future growth of DERs, grid flexibility and other, more qualitative benefits anticipated to result from the development of a modern grid. Subsequently, SCE refined its analysis based on additional engineering studies, pilot projects, and more detailed financial evaluations that validated most of SCE's Grid Modernization scope included in the request, but also indicated that some of the scope could be delayed to a later time in the future. As a result, SCE modified its request in its rebuttal testimony, removing (1) Circuit Tie Upgrades and (2) Subtransmission Relay Upgrades.[274]

The Coalition of California Utility Employees (CUE) generally supports SCE's Grid Modernization request. In particular, CUE agrees with SCE's request to augment its WCR program to include enhanced DA.[275] However, CUE objects to SCE's removal of the Subtransmission Relay Upgrades on the grounds that these upgrades are still needed.[276] SCE does not see a need for these upgrades in this GRC period, but anticipates including this request in a future GRC, once DER penetration levels reach a point where such issues are pressing.[277]

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[269] *See* Exhibit TURN-06, pp. 56-65.
[270] *See* Exhibit TURN-10, pp. 22-23.
[271] *See* Exhibit SEIA-Vote Solar, p. 7.
[272] *See* Exhibit SEIA-Vote Solar, pp. 7-8 and 51.
[273] *See* Exhibit SEIA-Vote Solar, pp. 20-34.
[274] *See* Exhibit SCE-18, Vol. 10, p. 4-5; *See also* Exhibit SCE-18, Vol. 6, p. 18.
[275] *Prepared Rebuttal Testimony of David Marcus on Behalf of the Coalition of California Utility Employees* (CUE) pp. 1-2, 11-12 (June 16, 2017) (CUE Rebuttal).
[276] *See* CUE Rebuttal, pp. 3-4, 15, and 32-33.
[277] *See* Exhibit SCE-18, Vol. 10, p. 4-5; SCE-18, Vol. 6, p. 19; SCE, Tolentino, Tr. 11/1499-1500.

Although SBUA submitted certain recommendations concerning Grid Modernization[278] and SCE submitted rebuttal testimony addressing SBUA's recommendations,[279] SCE and SBUA entered a stipulation resolving the issues between them during evidentiary hearings.[280]

Contrary to ORA's and the intervenors' arguments, the evidentiary record shows that:

- SCE must improve reliability, given metrics that show that SCE's reliability is declining compared to historical levels and compared to other utilities and given customer demands.
- SCE's Grid Modernization proposal focuses on foundational, "no-regrets" programs and projects needed to improve reliability with the flexibility to accommodate high DER growth in the future. Therefore, SCE's proposal is not premature and its remaining requests should be implemented now.
- SCE's proposal is cost-effective as evidenced by SCE's BCA, which shows net benefits even though it only accounts for certain narrow, easy-to-quantify reliability benefits. Cost-effectiveness is also shown by SCE's analysis of the payback period of key Grid Modernization programs. Further, only SCE's approach yields sufficient reliability, safety and cybersecurity results.
- Customer-site data sources, such as DER telemetry, inverters and AMI, are necessary but not sufficient to provide grid-wide visibility, control, and operational flexibility.

4.10.1. SCE's Reliability is Declining and Must be Improved

SCE's reliability is declining compared to historical levels.[281] SCE is also squarely in the third quartile in J.D. Power and IEEE reliability surveys, demonstrating that SCE is not keeping up with its peers.[282] A major driver of SCE's Grid Modernization program is its goal to bring the reliability of its grid back to where it has been historically and, further, to improve reliability to keep pace with the electric industry, in a prudent and targeted manner.

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[278] Exhibit SBUA-Michael Brown, pp. 10-21.
[279] Exhibit SCE-18, Vol. 10, pp. 2-3, 19.
[280] *See* SCE-SBUA-1, p. 2.
[281] *See* Exhibit SCE-18, Vol. 10, pp. 19-21.
[282] SCE, Tolentino, Tr. 11/1528, lines 1-13; SCE-18, Vol. 10, pp. 20, 21-26.

Citing a CPUC reliability report from 2006-2015,[283] ORA concludes that SCE's reliability has been improving over the past ten years.[284] However, that report does not provide an apples-to-apples comparison between SCE's reliability metrics, which exclude planned outages, and PG&E's, which appear to include them.[285] This provides a misleading impression that SCE's reliability is better than PG&E's when it is actually worse.[286]

More problematically, all of the cited metrics include Major Event Days (MEDs),[287] an approach that SCE has shown to be inappropriate when measuring a utility's historical reliability performance,[288] comparing utilities,[289] or targeting spending.[290] When MEDs are excluded, there is an increasing trend in SAIDI for SCE during the 2006-2015 period, indicating a trend of worsening reliability.[291] TURN even acknowledges this trend.[292] By 2015, SCE's metrics were the worst of the California IOUs.[293] PG&E's metrics have continued to exhibit a decline in SAIDI with MEDs excluded, indicating a trend of

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[283] Exhibit SCE-109: California Electric Reliability Investor-Owned Utilities Performance Review 2006-2015 (May 9, 2016).

[284] *See* Exhibit ORA-09, p. 49.

[285] *See* Exhibit SCE-110 (showing for PG&E 2006 SAIDI including MEDs and planned outages of 311) compared with Exhibit SCE-109, p. 10 (showing PG&E SAIDI of approximately 311); *See also* ORA, Tom Roberts, Tr. 18/2736-2737.

[286] SCE, Tolentino, Tr. 11/1509.

[287] SCE, Tolentino, Tr. 11/1527, lines 8-12.

[288] SCE-18, Vol. 10, p. 20 and n. 62 (quoting IEEE Standard 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices, Section 1.3 Purpose);*See* CCUE Rebuttal, p. 7, lines 3-14; *See also* D.96-09-045, 68 CPUC2d 80 Appendix A thereto, p. 2, Section 4.c, Excludable Major Events ("Each utility will exclude from calculation of its reliability indices major events that meet either of the two following criteria: (a) the event is caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government, or (b) any other disaster not in (a) that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event."); *See also* D.96-09-092, 68 CPUC2d 275, p. 46 (establishing SCE's Performance Based Ratemaking mechanism and stating that the reliability metrics upon which the performance incentive would be based "… should exclude the impact of less frequent events like major storms…").

[289] SCE-18, Vol. 10, p. 20; *See also,* SCE, Tolentino, Tr. 11/1527-1528; 1533, 1535, and 1538-1539 and Tr. 12/1680 lines 10-21; ORA, Roberts, Tr. 18/2734-2735; Exhibit ORA-108, p. 7 (letter from Energy Division Director, Paul Clanon, indicating its agreement that using IEEE Standard 1366-2003, which is a standard for how to exclude major event days, "would . . . provide consistency in comparing reliability data from different utilities across the country.").

[290] *See* ORA, Roberts, Tr. 18/2733-2734; *See also* Exhibit ORA-107, p. 28.

[291] SCE, Tolentino, Tr. 11/1527-1528; SCE-18, Vol. 10, p. 20 and footnote 64.

[292] *See* Exhibit TURN-04, p. 43 ("SCE claims that its reliability performance is flat to decreasing. This is true to a certain extent, especially when one considers SAIDI and SAIFI with Major Event Days (MED) excluded.").

[293] CCUE Rebuttal Testimony at p. 7, lines 7-9.

improving reliability.[294] And ORA acknowledges that when MEDs are excluded SCE's SAIDI is approximately 35 minutes higher (meaning worse) than SDG&E's for 2012-2015.[295] When the reliability data from year 2016 is included, SCE's trend of worsening reliability is even more pronounced.[296]

The recent J.D. Power surveys of business customers also shows SCE ranked in the fourth quartile for the subcategory of heat storm reliability, showing a decline from the previous year.[297] At the same time, SCE customer satisfaction regarding price is solidly in the top half of the second quartile in both the business and residential surveys.[298] SCE also provided evidence from its Summer Discount Plan, which showed high customer attrition after service interruption. This evidence further buttresses the notion that customers value reliability and are willing to pay for increased reliability.[299]

ORA also asserts that SCE requires a statutory or other basis to improve reliability, but SCE has provided clear statutory and regulatory support for its need to improve reliability.[300] SCE has also provided examples of the consequences it faces when it does not stay apace with expectations and reliability standards in the electric industry.[301]

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[294] *See* Exhibit SCE-18, Vol. 10 p. 20; *See* Exhibit TURN-122, p. 13 (Table 3, showing PG&E's distribution SAIDI without MEDs).

[295] *See* ORA, Tom Roberts, Tr. 18/2740-2741; *See also* Exhibit SCE-111 compared to Exhibit ORA-107, p. 92.

[296] *See* Exhibit SCE-18, Vol. 10 p. 21 (Figure I-3 SAIDI Excluding MEDs 2006 – 2016).

[297] *See* Exhibit SCE-18, Vol. 10, Appendix A, pp. A-58 to A-67 (attaching ORA-SCE-218-TCR, Q. 01, showing J.D. Power fourth quartile results for the subcategory of Power Quality & Reliability entitled "Supply electricity during very hot or very cold temperatures").

[298] *See* Exhibit SCE-18, Vol. 10, pp. 21-23 (business customers shown in Figure I-4 and residential customers shown in Figure I-5). *See* Exhibit SCE-18, Vol. 10, Appendix A, pp. A-58 to A-67 (response to ORA-SCE-218-TCR, Q. 01).

[299] *See* SCE-18, Vol. 10, pp. 23-24; SCE, Tolentino, Tr. 12/1677-1678.

[300] *See* Exhibit SCE-18, Vol. 10, p. 24 lines 6-11 through p. 25 lines 1-2 (citing Assembly Bill (AB) 66 (Muratsuchi), Local Electric Reliability, which added Section 2774.1 to the Public Utilities Code); SCE-18, Vol. 10, pp. 27-28 (citing D.10-06-048, *Decision on Pacific Gas and Electric Company Request to Implement a Program to Improve Electric Distribution System Reliability*, pp. 3 and 13-14 (June 24, 2010)).

[301] *See* Exhibit SCE-18, Vol. 10 p. 25-26 (citing D.00-02-046, p. 32, Cal. Pub. Util. Code § 451, and I.16-07-007 *Order Instituting Investigation Order to Show Cause and Notice of Hearing*, p. 6 (Long Beach OII) (July 14, 2016).

4.10.2. SCE's Grid Modernization Proposal is Primarily about Reliability and Safety, is Not Premature and Must Be Implemented Now

4.10.2.1. Grid Modernization is Primarily Driven by Reliability Goals

ORA argues that the primary purpose of SCE's Grid Modernization program is to meet the goals of the DRP and enable DERs.[302] It concludes that SCE's request is therefore premature and must await the outcome of the DRP proceeding. SCE has clearly demonstrated that its Grid Modernization request is primarily about reliability.[303] As Mr. Tolentino explained at hearings:

> … when you read our testimony, the initial benefit that we talk about is safety and reliability. And when you dive into the locational aspects of the programs that we put forth, specifically our distribution automation program, you can see that approximately 60, maybe 70 percent of the circuits we are targeting are for reliability purposes. The WCR circuits, the 600 WCR circuits that we are proposing to install distribution automation on are for reliability benefits. The remaining 263 circuits are for DER enablement.[304]

Every distribution infrastructure project we embark on for reliability purposes will support DER integration and may provide substantial benefits down the road as DERs proliferate.[305] To sweep all infrastructure projects that in any way relate to DERs into the DRP framework is overbroad and impractical. The DRP framework should not apply to distribution projects developed primarily for reliability.[306]

SEIA-Vote Solar adopts ORA's prematurity argument. But with respect to SCE's Motion for a Grid Modernization Memorandum Account for 2017 (Motion), SEIA took the opposite position, stating that many of these same investments were, instead, primarily related to reliability.[307] With respect to substation automation, SEIA stated that the "grid modernization improvements represented here have benefits to ratepayers that extend well beyond the support of DER adoption and the realization of DER value, including <u>improved operational flexibility and improved resiliency</u>."[308] SEIA took similar

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[302] *See* ORA-09 pp. 12-14, SEIA-Vote Solar pp. 10-11.
[303] *See* Exhibit SCE-10, Vol. 2, pp. 5-7, 56-58, 70-71, 79-80, 84, 110-111; *See also* Exhibit SCE-18, Vol. 10A4, pp. 12-14 and Figure I-2 on p. 14; SCE, Payne, Tr. 10/1226-1227; SCE, Tolentino, Tr. 11/1505-1506, and SCE, Tolentino, Tr. 12/1573 and 1639-1640.
[304] *See* SCE, Tolentino, Tr. 11/1505 line 24-1506 line 8.
[305] *See* SCE, Tolentino, Tr. 12/1575-1576.
[306] *See* SCE-18, Vol. 10, p. 14.
[307] *See* SCE-120, p. 4.
[308] Exhibit SCE-120, p. 4 (emphasis added).

positions with respect to the switching and remote fault indicators.[309] With respect to switching, SEIA stated:

> Here again SEIA does not dispute the potential value of SCE expanding its fleet of remote switches but questions the reasonableness of laying the costs of this investment at the feet of DERs or the goals of the DRP proceeding. The primary benefit of this effort is reliability and operations of the distribution system, with the usefulness for better management of DERs being a secondary benefit, and remote fault indicator technology proposed as part of SCE's distribution automation.[310]

At that time, SEIA agreed that the primary benefit of these Grid Modernization programs was reliability. SEIA seems less concerned with prematurity and more concerned with making sure that the costs of Grid Modernization are not attributed to DERs.[311]

4.10.2.2. Like Reliability, Safety is an Important Grid Modernization Benefit

ORA and TURN both acknowledge the connection between reliability and safety.[312] Yet ORA and TURN both argue that safety is not the primary justification of SCE's Grid Modernization request.[313] ORA minimizes this connection to safety, arguing that "reliability issues typically do not impact SCE employees or the general public" and "where they could . . . they do so only indirectly and the impacts are not immediate."[314] But SCE's principal responsibility is to safely and reliably deliver electricity to its customers. The reliability of electric service and the health and safety of those who use it are interwoven.[315] Not only does electricity enable productivity and convenience, it also powers

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[309] *See* SCE Exhibit-120, pp. 4-6. Although SEIA-Vote Solar's witness went to some length at the evidentiary hearings to distance himself from that DRP filing (SEIA-Vote Solar, Volkmann, Tr. 20/2834-2838*),* he specifically touted his work for SEIA in the DRP proceeding as among his qualifications for serving as a witness in this GRC proceeding. *See* Exhibit SEIA-Vote Solar, p. 5, lines 10-17.

[310] *See* Exhibit SCE-120, p. 6 (emphasis added).

[311] *Id.* at p. 3 ("SEIA does not object to the utility seeking to establish the requested memorandum account. However, we do have concerns regarding the extent to which the costs identified should be attributed in whole or in part to the DRP effort generally or DERs specifically will or should be attributed solely to supporting the adoption of DERs or to the realization of DER value.").

[312] *See* Exhibit TURN-10, p. 23 ("Safety and reliability are certainly related, and any outage has health and safety implications due to the very fact that there is no electric service."); ("Lack of electric service can have serious health and safety impacts on people who rely on certain medical devices or on air conditioning during a heat wave.").

[313] *See* Exhibits ORA-09, p. 44, TURN-10, pp. 22-23.

[314] *See* Exhibit ORA-09, p. 31.

[315] SED, Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001, pp. 43-44; *See also* Exhibit SCE-18, Vol. 10, pp. 28-30 (providing examples of reliability's impact on safety).

functions that keep our customers safe.[316] For those customers and members of the public who have their safety impacted by reliability issues, the indirect nature of the impact doesn't make the impact less tangible.

The Commission best explained this link between safety and reliability in its investigation of the Long Beach outage, explaining:

> The Commission has repeatedly stated that public safety is a top priority and that operating a safe system also includes the reliable provision of electricity. Without power, numerous unsafe conditions can occur. Traffic signals do not work, life support systems do not work, water pumps do not work, and communication systems do not work … In short, there is a strong presumption that power should remain on for public safety reasons.[317]

Grid modernization will reduce the number of customers impacted by outages, outage frequency, and outage duration. This means customers – including customers responsible for maintaining the safety, security and health of customers living in SCE's service territory – will experience fewer and shorter periods without electric service. Specifically, by improving our visibility of the real-time conditions of the distribution system, Grid Modernization will achieve an approximately 30 minute reduction in the time needed to locate and resolve many of these safety incidents, such as exposed high-voltage equipment resulting from downed power lines and displaced vault lids.[318] This will have a clear and positive impact on public safety by reducing the amount of time the public is exposed to potential safety hazards. While the dollar value of the safety benefits provided by Grid Modernization necessarily cannot be calculated with precision, we are confident that our efforts to modernize the grid will promote the safety of our customers and the public at large. Without a doubt, safety is a primary justification for Grid Modernization.

4.10.2.3. SCE's Grid Modernization Program Includes "No Regrets," Foundational Projects

SCE has developed its Grid Modernization proposal to include foundational capabilities that will be needed regardless of the outcome of the DRP. The Commission has acknowledged the need for

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[316] *See e.g.,* Exhibit SCE-18, Vol. 10, p. 29, lines 9-12.
[317] Long Beach OII, pp. 6-7 (July 14, 2016) (emphasis added) (internal citations omitted).
[318] *See* Exhibit SCE-18, Vol. 10 Appendix A, A-68 to A-82 (response to TURN-SCE-052-Q3.d.i.3).

"foundational investments in information, communication and operational systems..."[319] The More Than Smart Working Group (MTS) Final Report also acknowledged the long development timelines required to modernize a large utility distribution system and the need to modernize, even in the face of business and regulatory uncertainty.[320] That report argues for mitigating the timing risk by "identifying those investments that are required under any future scenario."[321] MTS explains that:

> [t]hese "no regrets" investments include advanced field telecommunications networks and increasing grid operational visibility – to allow more operational data, moving freely, in real time. This effort can be accelerated by focusing initial efforts within the development of optimal or preferred locations, revising in-flight programs such as fault indicator, switch automation, and capacitor control programs to offset otherwise expenditures that would become obsolete.[322]

SCE showed in rebuttal testimony that these are the exact capabilities that SCE includes in its Grid Modernization program and for precisely the reason articulated by MTS.[323] These foundational capabilities provide positive benefits and create "no regrets" for SCE's customers.[324]

SCE has also shown that its programs are well-tested.[325] SCE has conducted rigorous technology assessments, demonstration projects and pilots to assess the technologies we are planning to deploy. SCE utilized the Irvine Smart Grid Demonstration (ISGD) project that was substantially completed in 2015 to inform its Grid Modernization plan. One specific example includes the SA-3 standard, which resulted from successful demonstration and in-service testing we performed at ISGD's MacArthur SA-3 pilot. Other Grid Modernization technologies demonstrated in ISGD and in SCE's technology labs during the 2012-2016 timeframe included DA, Distribution Voltage and VAR control, and FAN technologies.

Nevertheless, ORA argues that Grid Modernization should not begin before we obtain the results of ongoing pilot and demonstration projects.[326] To illustrate its point, ORA includes a figure from the

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[319] *See* R.14-08-013, *Assigned Commissioner's Ruling On Guidance For Public Utilities Code Section 769 – Distribution Resource Planning*, dated February 6, 2015, p. 7.
[320] *See* Exhibit SCE-18, Vol. 10, p. 16.
[321] *Id.,* (emphasis added).
[322] *Id.,* (emphasis added).
[323] *See* Exhibit SCE-18, Vol. 10, pp. 16-17.
[324] SCE, Tolentino, Tr. 11/1679, lines 11-13; SCE, Payne, Tr. 10/1283-1284.
[325] SCE's ongoing pilots are largely to test emerging technologies that are not included in SCE's Grid Modernization program in this GRC. SCE intends to incorporate the results of these pilots when available and as appropriate to inform programs beyond 2020.
[326] *See* Exhibit ORA-09, pp. 24-31 and 38-41.

MTS Final Report that shows the lifecycle for utility infrastructure and technology deployment projects.[327] But that lifecycle figure was included in the Final Report to support the exact opposite position. MTS argues that "reducing the development time cycle for new designs and related technology solutions is critical" and explains that "there are opportunities to consider accelerating the front end of the lifecycle involving research, development and demonstration and business and regulatory decision making."[328] ORA acknowledged that some of the ongoing pilot and demonstration projects are not scheduled to be completed until 2020 and that further time is required after these results come out for a request to be incorporated in a GRC application.[329] Therefore, under ORA's approach, a Grid Modernization request would not be possible until the 2024 GRC.

SCE intends to incorporate the results of these pilots when available and as appropriate to inform programs beyond 2020.[330] But the idea that SCE must complete all demonstration projects related to modernizing the distribution grid before SCE can make any modernizing improvements flies in the face of the MTS recommendation. Moreover, this timeframe is unrealistic given the pressing needs on the distribution grid and California's ambitious environmental objectives (*see* Section 4.10.2.5).

4.10.2.4. All of SCE's Grid Modernization Programs, Even Those That Relate to the DRP, Should be Considered on Their Merits in the GRC

Rather than analyze each Grid Modernization program on its own merits, ORA and SEIA-Vote Solar suggest that any Grid Modernization projects that are DER-related need to await the outcome of the DRP.[331] TURN launched this exact argument in PG&E's 2017 GRC, arguing that "the Commission should remove from the scope of this case PG&E's premature effort to obtain funding for programs that are the subject of its recently filed DRP application."[332] The Commission was clear that this blanket rejection is inappropriate:

> The scope of this proceeding should include evaluation of all of PG&E's forecast distribution-related investments, even if they may be conceptually related to the DRP proceeding. Like all of its forecast investments, PG&E must meet its burden to demonstrate

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[327] *See* Exhibit ORA-09, p. 38.
[328] *See* Exhibit SCE-18, Vol. 10, p. 18.
[329] ORA, Roberts, Tr.18/2725-2726.
[330] *See* Exhibit SCE-18, Vol. 10, p. 18, n. 49.
[331] *See* Exhibits ORA-09, pp. 32-55; TURN-06, pp. 54 and 71; SEIA-Vote Solar, pp. 8-16.
[332] A.15-09-001, Assigned Commissioner's Ruling and Scoping Memo in PG&E's 2017 GRC, p.13 (December 1, 2015).

that these investments are reasonable in order to be authorized to move forward with those that are established to be necessary beginning in 2017.[333]

As with PG&E's Rate Case, the Commission should consider each program included in SCE's Grid Modernization request on its own merits. In fact, the Commission has stated a preference for considering all electric distribution reliability matters in an integrated fashion in the GRC. This allows "consideration and prioritization of all types of reliability programs (existing, expanded or new), not only in the context of reliability but in the context of the overall base revenue requirement."[334] Moreover, in the last GRC, while the DRP was pending, the Commission encouraged SCE to use authorized expenditures on T&D infrastructure challenges being addressed with in that proceeding.[335] It is difficult to understand how adoption of improved technologies and approaches to address these challenges was not premature then, but is premature now.

The majority of SCE's Grid Modernization request – SCE's automation of its worst-performing circuits and the system-wide telecommunication, cybersecurity, and analytics infrastructure to support grid operations – falls outside of the purview of the DRP.[336] Likewise, the approach to determining net benefits of DER-related investments, consistent with Public Utilities Code Section 769 (d), does not preclude the Commission from evaluating proposed grid upgrades in this GRC using criteria the Commission has always used. In the context of reliability programs, the Commission is experienced in determining net benefits through consideration of cost-effectiveness analyses.[337] Moreover, the GRC proceeding and Section 769(d) align in their objectives to make sure that customer rates are just and reasonable.

ORA's approach to analyzing SCE's Grid Modernization programs – and SEIA-Vote Solar's reflexive support of that approach[338] – is the most blatant example of failing to consider SCE's request on its merits. ORA admits that prior to considering SCE's Grid Modernization request in the GRC, ORA

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[333] *Id.*

[334] D.10-06-048, *Decision On Pacific Gas And Electric Company Request To Implement A Program To Improve Electric Distribution System Reliability*, p. 19 (June 24, 2010).

[335] *See* Exhibit SCE-112.

[336] *See* Exhibit SCE-18, Vol. 10, pp. 12-16.

[337] D.10-06-048, *Decision on Pacific Gas and Electric Company Request to Implement a Program to Improve Electric Distribution System Reliability*, pp. 13-14 (June 24, 2010) (Cornerstone Decision). Also available at 2010 Cal. PUC Lexis 234.

[338] Exhibit SEIA-Vote Solar, p. 7, lines 1-4.

presumed that this request was premature.[339] ORA's witness Tom Roberts then propounded "well over a thousand individual data request questions"[340] and conducted two site visits.[341] Mr. Roberts admitted that many of these questions were for his own background or for purposes of the DRP proceeding.[342]

ORA propounded more than 100 data request questions related to SCE's proposed GMS, WAN, CSP and SA-3 programs alone.[343] Yet for each of these programs, Mr. Roberts recommended zero dollars simply because these programs are "integral" to SCE's Grid Modernization program and therefore premature. Mr. Roberts did not need to propound data requests to conclude that programs in SCE's Grid Modernization program were integral to that program. Mr. Roberts cited only one of these data request responses and only to show that the program was integral to Grid Modernization.[344] On the stand, Mr. Roberts admitted that he did not complete his analysis related to these four programs because he simply ran out of time:

> My testimony is rather light on these sections, because I frankly ran out of time. I did a lot of discovery with the intention of having a thorough engineering-based analysis on every one of these systems. I just didn't have a chance to complete that.[345]

This testimony simply cannot meet even the lowest of burdens. Although SCE has the burden of proof, that burden is met if accompanied by sufficient justification and left unrebutted.[346] To claim an alternative recommendation, ORA must present evidence sufficient to support its alternative.[347] ORA's recommendation of "zero" dollars for programs "integral" to grid modernization simply does not meet that burden. If the Commission agrees, it should disregard ORA's recommendation.

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[339] ORA, Tom Roberts, Tr. 18/2721.
[340] ORA, Tom Roberts, Tr. 18/2682.
[341] ORA, Tom Roberts, Tr. 18/2715.
[342] ORA, Tom Roberts, Tr. 18/2716.
[343] ORA, Tom Roberts, Tr. 18/2716 (acknowledging 109 questions on SA-3 alone).
[344] Exhibit ORA-09, p. 117, line 7 and n. 390.
[345] ORA, Tom Roberts, Tr. 18/2719.
[346] *Re Pacific Bell*, D.87-12-067 at p. 22, 27 CPUC2d 1; *Universal Studios Inc. v. Southern California Edison Co.*, D.04-04-074, pp. 31-32, 2004 Cal. PUC LEXIS 173; *Re Golden State Water Co.*, D.07-11-037, 2007 Cal. PUC LEXIS 648.
[347] *Re Pacific Bell*, D.87-12-067 at p. 22, 27 CPUC2d 1.

4.10.2.5. The Grid Modernization Efforts Need to Begin Now

Intervenors question whether any actual problems exist today that require "immediate action,"[348] preferring instead to wait "for a problem to occur."[349] But this approach is myopic and fails to appreciate the current reliability challenges on SCE's system. It is also divorced from the practical reality of upgrading a system as large as SCE's.[350] The pace of Grid Modernization is particularly modest given SCE's and SEIA's long-term projected DER penetration levels,[351] the increasing complexity of the distribution grid,[352] and ambitious state environmental policy objectives.[353] SCE needs to begin this level of modernization now.[354] Given the time it takes to make system-wide upgrades,[355] SCE will not be able to react quickly enough if it waits for problems to occur in large numbers and our customers will have to endure further declines in reliability.[356]

4.10.3. SCE's Proposal is Cost-Effective and is the Only Proposal that Will Achieve Sufficient Reliability Improvement

When undertaking any service improvement project, utilities must address two questions: (1) what level of improvement is necessary; and (2) is the proposed solution cost-effective to achieve that level of improvement? The previous section clearly demonstrated that the level of reliability improvement SCE is seeking is necessary to prevent continued reliability decline, to keep pace with the industry, and to prepare for changing grid conditions. SCE's current third- and fourth quartile performance needs to be improved upon. The remaining question is: are SCE's proposed solutions cost-effective? As discussed herein, SCE has plainly demonstrated that they are.

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348 *See* Exhibit ORA-09, pp. 36-37.
349 *See* Exhibit TURN-06, p. 88.
350 *See* Exhibit SCE-18, Vol. 10 p. 18, n. 55 (SCE's distribution grid includes approximately 4,600 distribution circuits fed by nearly 800 substations across approximately 50,000 square miles).
351 *See* SCE-18, Vol. 10A4, p. 50, lines 4-10 (citing Exhibit SEIA-Vote Solar, pp. 12-13), SCE-18, Vol. 10, Appendix A, pp. A-130 to A-131; *See also* SCE, Payne, Tr. 1254-1255.
352 SCE, Payne, Tr.10/1321-1323, 1325.
353 SCE, Payne, Tr.10/1240, lines 17-28; 1254-1255.
354 SCE, Payne, Tr. 10/1239-1240.
355 *See* SCE-18, Vol. 10 (Appendix C, pp. C-15, SCE GRC Workshop Presentation Evolving Our Grid, October 24, 2018, p. 14).
356 SCE, Payne, Tr. 10/1244-1245.

4.10.3.1. SCE's Grid Modernization Program, While Justified Based on Reliability Benefits Alone, Will Also Provide Many Other Benefits

SCE conducted a comprehensive BCA of its Distribution Automation (DA) proposal, combined with the GMS, CSP, FAN and WAN systems that support DA and are being proposed for deployment beginning in the 2018 GRC period. The analysis compared the reliability benefits with the total costs of deploying and maintaining these technologies. SCE's analysis confirms that even after correcting for the data error identified by SEIA-Vote Solar[357] and updating for 2016 reliability information,[358] SCE's proposed DA, GMS and communications technologies produce reliability benefits that exceed the associated costs by 16-27%.[359]

SCE's BCA is conservative in many ways. First, it only includes narrow quantifiable reliability benefits – the cost savings associated with customer minutes of interruption (CMI) avoided. But there are actually many other benefits that SCE did not quantify, including: improved public safety related to fewer and shorter outages; potential capital deferral and O&M savings; physical security and cybersecurity; customer choice and desires; quicker operator decision-making for planned reconfigurations; environmental improvements; and additional economic benefits.

Additionally, while the analysis assumes no DER growth beyond 2020, these projects will actually enable higher amounts of DER adoption for years to come. Likewise, this analysis only includes the DA for the 863 circuits proposed in the 2018 GRC, but includes the full cost of deploying the GMS, CSP, FAN and WAN – the deployment of which will be completed in subsequent GRC periods. That is, since future DA deployments will not likely require incremental GMS or communications expenditures (beyond what SCE forecasts in its BCA), these deployments should prove even more cost-effective.[360] Additionally, the value of each CMI avoided relies on taking the simple average of the two values that resulted from two surveys – a lower national average and a higher value for PG&E – which is a

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[357] *See* Appendix E – Reliability Improvement Calculations, SCE reliability technology BCA_Model 3_Correct Outage Data.xlsx, tab 1. Summary, pp. E-163 to E-166 (including errata on E-166A4).

[358] *See* Appendix E – Reliability Improvement Calculations: SCE reliability technology BCA_Model 2_Incorporate 2016 Reliability Performance.xlsx, tab 1. Summary, pp. E-159 to E-162.

[359] *See* SCE-18, Vol. 10A4, p. 32 and p. 33A4 (Figure I-8).

[360] *See* Exhibit SCE 18, Vol. 10, p. 31.

conservative approach, given the higher cost of doing business in California.[361] CUE provides additional examples of how SCE's BCA is conservative.[362]

SCE's BCA includes, as a benefit, the value of avoiding the need to conduct an engineering study on faulted circuits with reverse power flows. SCE estimates that this will save operators about 20 minutes per each switching operation.[363] The 20-minute calculated average is based on the experience of engineers performing these analyses to inform operating decisions today.[364] In reality, when there is an outage on a circuit with two-way power flows, the process for service restoration involves at least six steps and each step takes longer than 3 minutes.[365] SCE also is assuming that the tools and network models will be available in the future to expedite this process (even though they may not be). These factors make the 20-minute assumption a very conservative one.[366] While SCE's DA program will not eliminate the need for some operator and engineering analysis, 20 minutes is a reasonable estimate of the savings achieved.[367]

SEIA-Vote Solar recommended excluding these benefits.[368] SCE disagrees with this recommendation, for the reasons already stated.[369] However, even if these benefits are excluded from SCE's analysis, the benefit-cost ratios would decrease from 1.27 to 1.09 for the Worst Circuit Rehabilitation (WCR) circuits and from 1.16 to 1.00 for the WCR and DER-driven circuits.[370] In both cases, the reliability benefits alone still justify the associated costs for both circuit bundles.

SEIA-Vote Solar also takes issue with SCE's assumption, for purposes of analyzing reverse power flow, that combined heat and power (CHP) and energy storage will generate 100% of nameplate capacity.[371] SCE has explained why it is appropriate to make these conservative assumptions.[372] SCE has also explained that the necessary use of conservative assumptions to mitigate against system

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[361] *See* Exhibit SCE-18, Vol. 10, Appendix A, A-91 to A-92 and A-92, n. 2. SCE, Tolentino, Tr. 12/1660, lines 14-21.
[362] *See* Exhibit CUE Rebuttal, p. 36.
[363] *See* Exhibit SCE-18, Vol. 10, p. 48.
[364] *Id.*
[365] *See* Exhibit SCE-18, Vol. 10, p. 49.
[366] *See* Exhibit SCE-18, Vol. 10, p. 49.
[367] Transcript Vol. 12, p. 1672.
[368] *See* Exhibit SEIA-Vote Solar (Volkmann), pp. 27-34.
[369] *See* also Exhibit CUE Rebuttal, pp. 34-35.
[370] *See* Exhibit SCE-18, Vol. 10A4, p. 34.
[371] *See* Exhibit SEIA-Vote Solar (Volkmann), p. 28.
[372] *See* Exhibit SCE-18, Vol. 10, pp. 49-50 and Appendix A, pp. A-112 to A-115 (responses to SEIA-SCE-008 Q.8.1 – 8.4).

issues caused by DERs will be obviated by real-time visibility and analytical tools such as the GMS.[373] With these tools, SCE will know the direction of power flow on the circuit at any given moment, and will not have to use conservative assumptions to mitigate risks. Moreover, these tools will allow SCE operators to shift towards depending on DERs to meet load requirements, rather than treating these reverse flows as sources of reliability risk.[374]

4.10.3.2. Intervenors Mistakenly Assert that Only the Cheapest Option Should be Pursued

TURN suggests that SCE should only pursue the solution that is "the most cost-effective."[375] Likewise, ORA argues that its +1+1 automation should be pursued over SCE's 3-3 scheme, because of its shorter payback period.[376] SCE disagrees with the premise that it should only pursue least cost, or what TURN characterizes as the single most cost-effective, solution. Certainly, SCE's spending choices should be prudent when comparing costs to benefits and considering the required result. But when determining whether only the most cost-effective solutions should be pursued, one must consider whether this level of spending will achieve the desired outcome. CUE explains this best when it states:

> The relevant question is not whether there are declining marginal reliability benefits to greater sectionalization - there are - but whether there are also declining marginal costs, and whether the decline in marginal benefits is enough to make those benefits not worth pursuing.[377]

Approximately 80% of the 600 WCR circuits that SCE plans to automate to a 3-3 configuration in 2018-2020 already have a 1-1 automation scheme. That these 481 circuits still rank among the worst-performing in the system despite their 1-1 automation scheme clearly demonstrates the inadequacy of investing exclusively in the most cost-effective solution.[378] For SCE to improve its reliability measurably, additional levels of cost-effective programs must be pursued. The low levels of automation that ORA and TURN propose do not produce sufficient reliability improvements. As discussed below, an analysis of the intervenors' scaled-down reliability proposals compared to SCE's bears this out.

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[373] *See* Exhibit SCE-18, Vol. 10, p. 50 lines 12-17.
[374] *Id.*
[375] Exhibit TURN-06, p. 28.
[376] *See* Exhibit ORA-09, p. 107.
[377] *See* Exhibit CCUE Rebuttal Testimony of D. Marcus, p. 41.
[378] *See* Exhibit SCE-18, Vol. 10, p. 40.

4.10.3.3. SCE's Grid Modernization Proposal Will Improve Reliability Measurably, While Intervenor Proposals Will Not

ORA and TURN both recommend pursuing DA at a slower pace and lower scale than SCE's Grid Modernization proposal. ORA recommends maintaining DA at historical levels, while TURN proposes a scaled-down version of SCE's DA proposal. However, neither the estimated 4.5 minute SAIDI improvement from ORA's approach nor 9.9 minutes from TURN's approach would be sufficient.[379] By contrast, SCE's proposed DA program is estimated to result in SAIDI improvement of 23 minutes.[380]

SCE has shown that its reliability performance in 2016 (approximately 106 minutes of SAIDI excluding MEDs) places it in the third quartile in the (2015) IEEE survey of utilities across the U.S.[381] Meanwhile, SDG&E rests squarely in the first quartile[382] and PG&E is at least in the second quartile and close to the first.[383] SCE's proposed solution would boost SCE to the second quarter as to SAIDI.[384] In contrast, TURN and ORA's proposals keep SCE in the third quartile.[385]

Additionally, and as discussed in Section 4.10.5.3, SCE's proposal, which introduces Remote Intelligence Switches (RISs), is the only proposal that can prevent momentary interruptions and thereby reduce MAIFI.[386] In fact, the RIS has a benefit-cost ratio of 1.2, meaning that installing an RIS instead

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[379] *See* Exhibit SCE-18, Vol. 10A4, p. 43 (Figure II-9); *See* SCE-18, Vol. 10, Appendix E - Reliability Improvement Calculations: Reliability Benefits +1+1 2016 Reliability data 160 RCSs per yr.xlsx on pp. E-2 to E-20, Reliability Benefits of TURN 2M-1T DA on 110 WCR ckts w no tie 2016 data.xlsx on pp. E-21- E-39, CMI Summary Recalc w 2014-2016 DA on 54 Organic Growth ckts.xlsx, Reliability Benefits of +1+1 w RFIs 2016 data.xlsx on pp. E-43 to E-63 and Appendix B - Workpapers: Value of RFIs on 490 WCR Circuits on p. B-14. *See also,* SCE, Tolentino, Tr. 1528-29.

[380] *See* SCE-18, Vol. 10, Appendix E - Reliability Improvement Calculations: CMI Summary Recalc w 2014-2016 3-3 WCR & DER.xlsx on pp. E-64 to E-98, Reliability Benefits SCE 3-3 WCR & DER ckts 2014-2016 data.xlsx on pp. E-189 to E-216, S-55-1 ReliabilityImprovementAsFunctionOfDA WCR+DER TURN-026 Q4i.xlsx on pp. E-99 to E-113, S-55-4 RFI Benefits to Automated Circuits.doc on pp. E-114 to E-117, S-55-4A Averaged RFI Benefits in CMI.xlsx on p. E-118, S-55-5 GMS Benefits on Non-WCR and Non-DER Automated ckts.xlsx on pp. E-119 to E-146, S-55-6 Ageing Impacts on DER Ckts.xlsx on pp. E-147 to E-151.

[381] *See* Exhibit SCE-18, Vol. 10, pp. 26-27.

[382] *See* Exhibit SCE-111, p. 1 (Table 1.1, showing distribution SAIDI without MEDs of 57.71 for SDG&E in 2015) compared to SCE-18, Vol. 10A4, p. 27 (Figure I-7, showing 106 for SCE).

[383] *See* Exhibit TURN-122, p. 13 (Table 3, showing distribution SAIDI without MEDs of 72.4 for PG&E in 2015) compared to SCE-18, Vol. 10A4, p. 27 (Figure I-7, showing 106 for SCE).

[384] *Id.*

[385] *Id.*

[386] *See* Exhibit SCE-18, Vol. 10A4, pp. 41-42; SCE, Tolentino, Tr. 12/1597.

of an RCS produces incremental benefits that are 20% greater than the incremental costs.[387] TURN's and ORA's proposals do not affect the number of Momentary Interruptions (MI), and therefore will not reduce MAIFI.[388] Of the three proposals, only SCE's will meet our customers' needs and expectations.[389] Figure 1 summarizes the ORA, TURN and SCE proposals for DA and the supporting foundational technologies, including the scopes and associated reliability improvements.

Grid Modernization Proposal Summary

	ORA	TURN	SCE
Scope			
Distribution Automation			
Midpoint Switches/Circuit	1	2	3
Tie Switches/Circuit	1	1	3
Circuits/Year	80	37	288
Remote Fault Indicator Locations/Circuit	-	5	5+
Circuits/Year	-	218	288
Foundational Technologies			
Grid Management System	-	DERMS & ADMS	GMS
Communications	-	CSP	FAN, WAN & CSP
Reliability Improvements			
Improvements in service restoration following an outage			
Customers restored via remote switching*	50%	67%	75%
Remote switching restoration time (min.)	30	10	1
Reduced time to isolate fault in field (min.)	-	30	30
Improvements in reliability metrics			
Customer Minutes of Interruption (millions)	22.5	49.6	115.3
SAIDI	4.5	9.9	23.1
Customer Interruptions	-	-	200,000
MAIFI	-	-	0.04

* Assumes sufficient capacity is available on the adjacent circuit to support transferring the load. Increasing the number of tie switches would improve the likelihood of being able to perform the load transfer.

4.10.4. SCE Requires Grid Modernization for Real-Time Visibility; Use of Existing Data Sources and Networks Alone Is Insufficient

The intervenors suggest that SCE's Grid Modernization program fails to adequately utilize data from DER telemetry, AMI, smart inverters, and a DER provider network.[390] SCE recognizes that using

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387 *See* Exhibit SCE-18, Vol. 10A4, p. 32 and Appendix E – Reliability Improvement Calculations: SCE reliability technology BCA_Model 2_Incorporate 2016 Reliability Performance.xlsx, tab 1. Summary, pp. E-159a4 to E-162a4.

388 *See* Exhibit SCE-18, Vol. 10A4, 42, n. 134.

389 *See* Figure II-9, SCE-18 Vol. 10A4, p. 43.

390 *See* Exhibits ORA-09, pp. 41-44, and p. 59; SEIA-Vote Solar, pp. 48-51; and TURN-06, pp. 63-64.

such existing data sources within SCE's distribution operations is necessary to increase visibility and reduce the barriers to DER integration. SCE is already making progress, and even ORA recognizes that SCE's "requests for new software tools in this GRC signal an intention to more fully utilize SCE's AMI system."[391] This is why SCE includes, as one of SCE's GMS specifications, utilization of data from smart inverters as a required data source.[392] Moreover, in May of 2015, SCE conducted a smart meter optimization initiative and identified opportunities to further utilize this existing AMI infrastructure. This initiative informed SCE's GRC request. In particular, in developing its Grid Modernization program,[393] SCE has assumed it will use its available AMI data to improve situational awareness and foster DER integration.[394] SCE also intends to rely on the DER provider network for smaller DERs that do not provide time-critical gird reliability services.[395]

Existing data sources, such as DER telemetry, AMI infrastructure, smart inverters, and a DER provider network cannot, alone, provide the level of real-time visibility required to analyze and operate the distribution grid.[396] The AMI infrastructure was primarily designed and built to support billing applications and therefore is only able to communicate load usage data once every 24 hours, not in real time.[397] This is insufficient for operating the grid.[398] AMI infrastructure only measures net load (load minus generation), but not gross load or generation, which are needed to properly manage the distribution grid.[399] While more modern AMI infrastructure, such as the Silver Spring Networks used in the Maui smart grid pilot,[400] may operate as a field area network providing peer-to-peer communication and real-time visibility across a broad population of meters, SCE's older AMI infrastructure cannot do so.[401] New AMI infrastructure that provides these capabilities would be significantly more expensive

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391 Exhibit ORA-09, p. 41.
392 *See* Exhibit SCE-18, Vol. 10, Appendix A pp. A-124 to A-125 (Response to TURN-SCE-123, Q.17).
393 For example, SCE's Grid Analytics Application, which is included in its IT request (SCE-04, Volume 2, section 6) will fully utilize AMI data to aid in development of engineering, planning and operational functions.
394 *See* Exhibit SCE-18, Vol. 10, Appendix A pp. A-126 to A-127 (response to ORA-SCE-060-TCR Q. 9 and TURN-SCE-127, 3.h).
395 *See* Exhibit SCE-18, Vol. 10, p. 57.
396 *See* Exhibit SCE-18, Vol. 10, p. 35, n. 117 and Appendix A, p. A-126 (citing SCE response to ORA-SCE-060, Q.9); SCE, Payne, Tr. 10/1281 line 14 through 1282, line 1.
397 *See* Exhibit SCE-18, Vol. 10, p. 35; SCE, Tolentino, Tr. 11/1519; SCE, Tolentino, Tr. 12/1603.
398 SCE, Gooding, Tr. 13/1741.
399 *See* Exhibit SCE-18, Vol. 10, p. 35; SCE, Tolentino, Tr. 12/1602-1603.
400 SCE, Gooding, Tr. 13/1755-1756.
401 SCE, Gooding, Tr. 13/1754-1756.

than SCE's FAN.[402] Furthermore, the operator requires additional information about the fault location and type.[403] While AMI has the ability to identify which customers are affected by an outage, this information is insufficient to pinpoint the fault location, especially when many customers are impacted. As a result, operators must spend time driving the length of the circuit to locate the fault location.[404]

While generation data from telemetry from larger DERs and inverters via a DER provider network will be available in near-real time, such devices provide generation (not load) information and only at the respective DER locations. That is, they do not provide the operator power flow magnitude or direction (the state estimation information) along the entire circuit or at the circuit segment level.[405] Therefore, this telemetry is insufficient for identifying masked load conditions. In discovery, SCE cited an instance where this masked load resulted in an overload condition, stating that "[i]f SCE had the ability to correctly estimate generation and load at a circuit segment level, SCE would have the ability to identify this masked load condition."[406] TURN misinterpreted SCE's response as an admission that SCE had failed to request the appropriate telemetry[407] and incorrectly concluded that this telemetry would be enough.[408] The point is that telemetry at the DER location is insufficient to provide adequate state estimation along the circuit segment level.[409] Likewise, this telemetry data is currently quite limited and sporadic, given the low penetration of inverter-based devices along the circuit today.[410] Finally, telemetry at the DER location does not identify the location of the fault.[411]

SEIA-Vote Solar likewise discounts the issues associated with reverse power flows and masked load because, during an outage, behind-the-meter grid connected PV systems will disconnect.[412] But with real time visibility, DERs would not need to be disconnected and could actually help during an

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402 SCE, Gooding, Tr. 13/1764.
403 SCE, Gooding, Tr. 13/1741.
404 *See* Exhibit SCE-18, Vol. 10, pp. 9-10.
405 *See* Exhibit SCE-18, Vol. 10, p. 35.
406 Exhibit SCE-129 (SCE-TURN-127 Q.03.a); *See also,* TURN, Stephens, Tr. 20/2917-2919.
407 *See* Exhibit TURN-06, p. 60 ("…I do not understand why the telemetry was not demanded by the Company for routine use by grid operators."); *See also* TURN, Stephens, Tr. 20/2919, lines 13-17 ("Q: What evidence do you have that SCE did not demand telemetry from this generator? A: I have no evidence that they did not demand it, but it is obvious from their response that they did not have it.").
408 TURN, Stephens, Tr. 20/2920.
409 SCE, Tolentino, Tr. 11/1524.
410 *See* Exhibit SCE-18, Vol. 10, p. 35; SCE, Gooding, Tr. 12/1696-1697.
411 SCE, Tolentino, Tr. 12/1685.
412 *See* Exhibit SEIA-Vote Solar Prepared Testimony, p. 28.

outage.[413] Moreover, the disconnection of DERs actually creates a problem for accurate switching on the circuit since system operators do not know the gross load of the various circuit segments they are attempting to restore. At the evidentiary hearings, Mr. Tolentino explained the issues related to this disconnection and masked load as follows:

> So when we are restoring service [masked load] can be a big problem, because we don't understand how much load there is out there to restore. So when we have an outage, all the DERs on the system disconnect. So the load that they previously served will have to be served by Edison immediately following the restoration of service. Because we do not know what the load is in the specific houses and things that have DERs, we do not know how much load we are actually transferring. What that can do is overload components on the system or even cause a bigger outage by tripping other parts of our system as we restore service.[414]

Additionally, in order to perform a switching operation from a faulted circuit to an adjacent circuit, the operator needs information about both the circuit with the outage and the adjacent circuit. If load on the adjacent circuit is masked, the operator could overload that circuit.[415] Moreover, outages are not the only occasions when switching occurs. Again, Mr. Tolentino explained this at hearings:

> Mask load is not just an issue for abnormal configurations of the circuit. When we plan the system we also need to know what the load is on all of circuits and substations in the event that we may lose DER[s] or DER[s] aren't available at that time. So in an extremely cloudy day, for example, we may not have any PV output. We need to understand how much load is actually there so that we can serve it efficiently. So it is not just when we switch the circuit abnormally. It is also to understand how we plan the system moving forward.[416]

Apart from switching related to outages, SCE performs 22,000 planned switching operations on its system per year.[417] Operators would benefit from real-time information for all of these operations where DERs are present, not just during outages.[418]

Due to these limitations with the existing data sources, operators cannot rely solely upon them to accurately predict how much load will be transferred (and how much load-carrying capacity is available) under any given switching operation. For these reasons, TURN's suggestion that, in lieu of real-time

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413 Exhibit SCE-02, Vol. 10, p. 53, Figure III-16 and related discussion; SCE, Tolentino, Tr. 12/1575, lines 9-21.
414 SCE, Tolentino, Tr. 12/1599, lines 11-25; *See also* 1602, line 17 – 1603, line 2.
415 Exhibit SCE-02, Vol. 10, p. 46 and Example 3 and 4, p. A-4 and A-5; SCE, Tolentino, Tr. 12/1599.
416 SCE, Tolentino, Tr. 12/1600.
417 *See* Exhibit SCE-02, Vol. 10, pp. 17-18; SCE, Tolentino, Tr. 12/1600, lines 4-16.
418 *Id.*

telemetry, the operators instead consult historical smart meter data combined with the Grid Connectivity Model (GCM) and/or Advanced Distribution Management System (ADMS)/Distributed Energy Resources Management System (DERMS) is simply unworkable.[419] Likewise, SEIA-Vote Solar's approach of employing DERMS without the other aspects of the GMS would not enable real-time control and monitoring of DERs.[420]

4.10.5. Distribution Automation

SCE's Distribution Automation (DA) proposes to replace its Historical Circuit Automation with a more extensive program that targets WCR and DER-driven circuits. The DA program provides several important features. First, it provides real-time visibility to distribution system operators, with telemetry data points not only at a DER location but throughout the distribution circuits that will help identify power flow issues quickly and accurately.[421] Second, it facilitates remote fault isolation and service restoration, thereby decreasing outage duration and area of impact.[422] Third, the program increases operational flexibility with appropriately-sized line sections for circuit switching, which will minimize outages during planned maintenance and unplanned outages.[423]

SCEs proposed DA program differs from its Historical Circuit Automation program in scope, scale, and pace. In particular, SCE proposes upgrading its circuits to a 3-midpoint switch and 3-tie switch scheme (3-3 scheme) compared to a mostly 1-1 scheme deployed today. This is needed for system planners and operators to perform their jobs without relying on conservative assumptions or risking outages.[424] This 3-3 scheme is also preferable to a 2-midpoint switch scheme because it distributes the circuit automation across the circuit in evenly-sized load blocks.[425] Since 80% of SCE's worst-performing circuits already have one midpoint switch,[426] upgrading these to a 2-midpoint switch scheme would require either: (a) moving the existing midpoint switch, or (b) installing two new

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419 *See* Exhibit TURN-06, pp. 63-64.
420 SCE, Gooding, Tr. 12/1706.
421 *See* Exhibit SCE-02, Vol. 10A6, p. 35A6; Exhibit SCE-18, Vol. 10, p. 37.
422 *See* Exhibit SCE-02, Vol. 10A6, p. 35A6; SCE, Tolentino, Tr. 12/1573; Exhibit SCE-18, Vol. 10, p. 37.
423 *See* Exhibit SCE-02, Vol. 10A6, p. 35A6; SCE, Tolentino, Tr. 12/1573; Exhibit SCE-18, Vol. 10, p. 37.
424 *See* Exhibit SCE-18, Vol. 10, pp. 37-38 and n. 119. SCE defines real time visibility as the level needed to operate the system, without having to make conservative assumptions or avoid switching operations based on lack of knowledge of load conditions and has determined that this requires a state estimation error of +/- 5%.
425 *See* Exhibit SCE-18, Vol. 10, Appendix A, pp. A-128 to A-129 (SEIA-Vote Solar-SCE-001 Q. 01.31).
426 *See* Exhibit SCE-18, Vol. 10, pp. 38 and 40.

midpoint switches and disabling the existing midpoint switch's auto-restoration feature. SCE's 3-3 scheme avoids these associated costs while providing additional benefits.[427] SCE proposes upgrading current Remote Control Switches (RCSs) and installing Remote Intelligence Switches instead of RCSs (where new switches are needed)[428] and deploying remote fault indicators (RFIs) along the circuit.[429]

This DA program also targets more circuits per year. Under SCE's Historical Circuit Automation program, SCE targeted 160 switches per year (around 80 circuits).[430] But under the new DA program, SCE proposes targeting 200 WCR circuits per year (600 in total over this GRC period). SCE also proposes targeting 88 DER-driven circuits per year (263 over this GRC cycle), including 63 circuits experiencing organic DER growth, 126 circuits to promote optimal DER locations, and 74 circuits as part of SCE's deferral pilots.[431]

ORA's DA forecast provides funding for SCE's Historical Circuit Automation, using 2016 recorded expenditures as the basis. Given that 80% of SCE's WCR circuits already have a 1-1 scheme, SCE interprets this to mean installation of 1 additional midpoint switch and 1 additional tie switch (+1+1) on these circuits.[432] ORA has not objected to this characterization.[433] ORA argues that the scope and pace of SCE's proposed DA program is too aggressive and expensive, and that SCE can achieve close to the same level of reliability through its Historical Circuit Automation.[434] SEIA-Vote Solar adopts ORA's recommendation.[435]

TURN recommends a scaled-down version of SCE's DA program. TURN opposes automation that replaces work typically done by operators (so called "grid operations automation") in favor of technology that provides operators more visibility and flexibility.[436] TURN instead recommends installing five RFIs on the 600 WCR circuits,[437] automating to a 2-1 configuration (rather than 3-3) on only the 110 of these 600 circuits that currently have no circuit tie, and deploying cheaper RCSs, rather

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427 *See* Exhibit SCE-18, Vol. 10, p. 38.
428 *See* Exhibit SCE-02, Vol. 10, pp. 49-50.
429 *See* Exhibit SCE-02, Vol. 10, p. 50.
430 *See* Exhibit SCE-02, Vol. 10, p. 36.
431 *See* Exhibit SCE-18, Vol. 10, p. 37.
432 *See* Exhibit SCE-18, Vol. 10, pp. 43-44 and n. 136.
433 *See* Exhibit ORA-09A, p. 110 and fn. 344.
434 *See* Exhibit ORA-09, pp. 94-103.
435 *See* Exhibit SEIA-Vote Solar Prepared Testimony, p. 7 lines 1-4.
436 *See* Exhibit TURN-06 pp. 24-25, pp. 50-55, pp. 68-71, and pp. 89-91.
437 *See* Exhibit TURN-06, p. 41.

than the RISs that SCE recommends. For DER-driven circuits, TURN recommends that, "if the Commission accepts SCE's assertion that it must address some operational challenges during this rate case cycle, prior to DRP guidance," then 54 of the 63 circuits targeted for organic DER growth should receive RCSs and RFIs over the GRC period.[438]

As discussed herein, there are several flaws in intervenors' arguments. When correcting these errors, it is clear that SCE's DA program is necessary and prudent.

4.10.5.1. ORA's Payback Analysis is Incorrect; SCE's Payback Period Is, In Fact, Five Years

ORA challenges SCE's conclusion that its 2018 DA program has a payback period of less than five years.[439] ORA argues instead that the payback period would exceed 13 years if the costs of necessary supporting technologies, such as WAN, FAN and GMS, are considered.[440] ORA also argues that a hypothetical +1+1 scheme would yield most of the reliability benefits provided by SCE's DA scheme, but with a significantly shorter payback period. ORA is incorrect. ORA's analysis includes several errors and omissions that understate the reliability benefits and overstate the capital costs associated with SCE's DA proposal, while making similar errors with respect to ORA's +1+1 scheme.

ORA understates the benefits of SCE's 3-3 DA program in several ways. First, ORA ignores the value of RFIs. In so doing, ORA excludes a large share of the quantitative reliability benefits included in SCE's BCA. RFIs provide additional value by reducing the time needed to identify fault locations. Second, ORA ignores the benefits associated with faster switching on circuits with existing distribution automation and avoided DER impact.[441] Third, ORA excludes the benefit of avoided momentary customer interruptions enabled by the fault interrupting capability of the proposed RISs, as discussed in Section 4.10.5.3.

ORA also overstates the costs of SCE's 3-3 DA program. ORA extends the payback analysis to include DA deployments in years 2021 and 2022, two years beyond the GRC timeframe.[442] ORA includes the costs of both WCR circuits (200 circuits per year) and DER-driven circuits (88 circuits per

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[438] *See* Exhibit TURN-06, p. 51 and pp. 72-73.
[439] *See* Exhibit ORA-09, pp. 104-105.
[440] *See* Exhibit ORA-09, p. 105.
[441] *See* Exhibit SCE-18 Vol. 10, Appendix E, pp. E-221 to E-224, Reliability Improvement Calculations - SCE reliability technology BCA_Model 1_TURN 26 Q55.xlsx, tab 2. BCR and PVRR Calcs.xlsx.
[442] *See* Exhibit SCE-18 Vol. 10, p. 44; CUE Rebuttal, p. 8.

year) for 2021 and 2022. However, the corresponding CMI reductions for 2021 and 2022 only include the WCR circuits, not the DER-driven circuits.[443] As a result, ORA's analysis overstates the DA costs for 2021 and 2022 by approximately 40%.[444]

SCE updated ORA's analysis to correct these errors. SCE's corrected analysis shows faster payback periods (even when including costs to be incurred in 2021 and 2022) than those indicated by ORA's analysis.[445] In fact, SCE's payback period for 3-3 DA (for the five years of deployment from 2018 to 2022) is 3.1 years compared to ORA's 9.1 years. When including the supporting technologies, SCE's payback period increases to 5.2 years, which is substantially less than ORA's estimated 13.4 years. SCE's payback period for DA and supporting technologies is 4.4 years for the GRC period.[446]

ORA commits the same errors as its 3-3 analysis when evaluating its hypothetical +1+1 scheme. In addition, ORA also underestimates the foundational costs of its +1+1 scheme by incorrectly assuming the costs of supporting technologies would decrease by 50%.[447] In fact, the GMS and communications costs are not driven by the number of field devices and would therefore not be reduced.[448] The payback period for a +1+1 scheme (for the five years of deployment from 2018 to 2022), for DA and supporting technologies, would be almost 5 years.[449] Contrary to ORA's claim, this payback period is comparable to the 3-3 DA payback period. However this scheme would fail to deliver the necessary reliability improvements and would therefore be an inferior DA solution.

4.10.5.2. TURN's Opposition to Automating Certain Operator Functions is Unwarranted

TURN recognizes the need to improve visibility of power flow and masked load.[450] TURN expresses concern with automation that has the potential to remove the traditional role the operator plays

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443 *See* Exhibit SCE-18 Vol. 10 at p. 44, CUE Rebuttal, pp. 11-12.
444 *See* Exhibit SCE-18, Vol. 10A4 p. 44.
445 *See* Exhibit SCE-18, Vol. 10A4, p. 45A4, Table II-5 and Appendix E, p. 186A4.
446 *See* Exhibit SCE-18, Vol. 10A4 and Appendix E, p. 186A4; *See also* CUE Rebuttal, p. 8-10 (calculating a 6.35 year payback period for SCE's 3-3 scheme over a 3 year period, compared to ORA's calculation of 10.5 years).
447 *See* Exhibit SCE-18, Vol. 10A4 p. 45A4; *See also* CUE Rebuttal p. 8, line 14-p. 9, line 3.
448 *Id.*
449 *See* Exhibit SCE-18, Vol. 10A4, p. 45A4, Table II-5 and Appendix E, p. 187A4.
450 *See* Exhibit TURN-06, p. 57 (recommending concentrating on improving visibility into power flow and masked load).

in grid state estimation, reconfiguration, and execution processes.[451] While TURN regards this as "a great vision for what distribution utilities should work towards over time,"[452] TURN's witness expresses concerns that SCE's DA is premature and will meet operator resistance to change.[453] TURN argues that SCE should focus instead on improving capabilities for accurate grid state estimation. TURN's concerns are not warranted for several reasons.

First, automation of some operator functions, through FLISR, is not new and utilities across the country are employing these capabilities with positive results.[454] In fact, SCE's DA program was, in part, modeled on some of the successes that came out of the Department of Energy's Smart Grid Demonstration Projects,[455] which employ similar FLISR technology in combination with smart meter technology to improve reliability. The reliability improvements achieved through those pilots were significant.[456]

When asked about these pilots at hearings, TURN's witness, Mr. Alvarez, argued that these programs were inconsistent with SCE's proposed approach in that they "don't require data to be pulled back to some centralized system to make those decisions."[457] Mr. Alvarez differentiated these pilots from SCE's proposal of "full automation with the grid management system implying that you don't even need maybe grid operators."[458] Then on redirect by his own counsel, Mr. Alvarez admitted that, in fact, at least one of those pilots was using SCE's proposed solution.[459]

TURN's witness also exaggerated the impact of SCE's automation proposal by suggesting that SCE was eliminating the need for grid operators. SCE is not proposing to eliminate grid operators. That is why TURN's witness, when questioned further, was unable to identify where in its testimony SCE said it would not need them.[460] To the contrary, the key objective of SCE's automation proposal is to empower operators with more precise and immediate power flow information along each circuit so that

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451 *See* Exhibit TURN-06, p. 54.
452 *See* Exhibit TURN-06, p. 54, lines 14-15.
453 *See* Exhibit TURN-06, p. 54-55.
454 *See* SCE, Tolentino, Tr. 12/1585, lines 7-17, & 1646; *See also* Exhibit SCE-18, Vol. 10, p. 9, n. 32.
455 *See* Exhibit SCE-02, Vol. 10, p. 22; *See also* Exhibit SCE-131.
456 *See* Exhibit SCE-131, p. v.
457 TURN, Alvarez, Tr. 20/2923, lines 1-3.
458 TURN, Alvarez, Tr. 20/2923.
459 TURN, Alvarez, Tr. 20/2932.
460 TURN, Alvarez, Tr. 20/2923-2924.

operators can make quick and safe switching decisions and better utilize resources connected to the distribution grid.[461]

SCE is proposing an automation scheme that would initially recommend switching actions to grid operators. Over time, once recommendations with respect to the initial switching decision prove consistently accurate, that decision-making process could become fully automated. But this would only impact operator decision-making connected with the first part load up (PLU) aspect of grid operations. Operators could then focus on the more complex switching operations to restore service to additional customers. Automation of the first PLU yields significant benefits to customers in terms of a reduction in outage restoration times, moving from 30 minutes to 1 minute for 75% of the customers on a faulted circuit.[462]

SCE has a 20-year track record of successfully implementing of automation programs. SCE has demonstrated that it can deploy automation technology across its system. SCE has also developed and refined the processes to integrate grid automation technologies into our workforce while also improving estimation of costs for deploying grid automation. Today, SCE has automatic load restoration schemes—that operate without grid operator intervention—deployed across our service territory as part of our substation automation systems. SCE is requesting funding to extend these capabilities more widely to the distribution grid as well.

4.10.5.3. TURN Overlooks the Importance of RISs

Like ORA, TURN trivializes the importance of RISs to SCE's proposal. TURN asserts that "the benefit that SCE expects to realize from more switches on the system does not depend on whether the switch is an RCS or an RIS."[463] SCE's goal is to improve reliability, and RISs deliver more reliability benefits than RCSs. RISs deliver higher benefits than RCSs irrespective of whether each circuit has one switch or three switches. RISs deliver higher benefits than RCSs irrespective of whether each circuit has one switch or three switches. TURN's witness acknowledged at hearings that RISs deliver MAIFI benefits while RCSs do not.[464] In particular, an RIS has the ability to interrupt a downstream fault <u>before</u> it activates the substation circuit breaker. This means that customers upstream of the RIS will experience

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[461] SCE, Tolentino, Tr. 12/1608-1610.
[462] *See* Exhibit SCE-18, Vol. 10, p. 29, fn. 96.
[463] Exhibit TURN-04, p. 46.
[464] TURN, Jones, Tr. 21/2988-2989.

no outage at all.[465] The RIS is the one element in the Grid Modernization program that can prevent momentary interruptions and thereby reduce MAIFI.[466]

TURN proposes using RCSs with basic sensors (RFIs) on grounds that this approach is less expensive and relies on proven technologies.[467] SCE's proposal will contain costs by enhancing existing RCSs with adequate sensors rather than replacing the RCSs with RISs.[468] The sensors SCE proposes for upgrading existing RCSs are of a higher quality than RFIs (which TURN proposes in lieu of RCS sensors) in that they provide voltage measurements.[469] Where no RCSs exist, installation of RISs is prudent because these devices yield needed reliability benefits, including MAIFI reductions.

4.10.6. Substation Automation

SCE has demonstrated why SA-3 is needed to support a modern grid, in particular by providing adaptive protection to fault current as DER penetration increases.[470] SA-3 will provide remote control and data acquisition from substation equipment (such as transformers, circuit breakers, and capacitors, and devices measuring current, voltage and power flow). SA-3 will utilize an open standards design to increase interoperability between systems and devices, allow for component upgrades from multiple vendors, and facilitate modern cybersecurity protections.[471] SA-3 will also work with the Adaptive Protection System under the GMS to ensure that SCE can adequately engineer and maintain configurations of protection systems as the grid changes over time.[472]

ORA recommends no funding for SA-3 because of this program's association with Grid Modernization and because "SCE does not have an active SA program."[473] ORA draws an incorrect conclusion that since SCE showed little or no recorded SA-3 expenditures for 2011-2015 in testimony, "SCE does not have an active SA program."[474] SA-3 is a new standard that addresses current needs, but substation automation is not new. In fact, SCE has been installing substation automation equipment on

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465 Exhibit SCE-18, Vol. 10, p. 41 lines 11-14; SCE, Tolentino, Tr. 11/1545, lines 3-6.
466 SCE-18, Vol. 10A4, pp. 41-42; SCE, Tolentino, Tr. 12/1597.
467 *See* Exhibit TURN-06, pp. 67-68.
468 SCE, Tolentino, Tr. 12/1610, lines 6-9, 1611, lines 4-8, & 1627, lines 21-26.
469 SCE, Tolentino, Tr. 12/1628, lines 3-8.
470 *See* Exhibit SCE-18, Vol. 10, pp. 71-72.
471 *See* Exhibit SCE-18, Vol. 10, p. 70.
472 *See* Exhibit SCE-18, Vol. 10, p. 72.
473 *See* Exhibit ORA-09, p. 117.
474 *Id.*

our system for approximately 20 years[475] and did so in the 2011-2015 time period. However, this work was not performed as standalone substation automation projects. Instead, the work was included as part of broader load growth and infrastructure replacement projects.[476] SCE explained in Section 4.10.2.4 above that ORA failed to sufficiently consider SA-3 on the merits.

TURN argues that SA-3 is not necessary to accommodate Grid Modernization.[477] TURN does support substation automation in support of Grid Modernization, but recommends using an advanced SAS-2 system as a substitute for SA-3.[478] SCE has explained why SAS-2 would be a suboptimal choice.[479]

TURN argues that SA-3, which enables operators to remotely reconfigure circuit breakers to protect against fault current from PV solar, is unnecessary. TURN's position is that PV solar systems present no risk of contributing to fault current and there is therefore "no need to adjust breaker settings due to the presence of PV solar."[480] But even at low penetration levels (10%) and depending on how DER is distributed along a circuit, DER may have a major impact on feeder protection.[481] While it is easy for TURN to dismiss fault current as a hypothetical problem,[482] SCE alone is responsible for making sure such problems do not materialize. Protection systems are the last line of defense against equipment damage and threats to public safety caused by fault current. SA-3 provides the foundational infrastructure that supports remote and more frequent protection configuration changes to field devices.

4.10.7. Communications Technology

SCE's Grid Modernization telecommunications technologies – a FAN to replace the aging NetComm system and its interim Distribution System Efficiency Enhancement Program (DSEEP), the CSP, and the installation of new fiber optic cable where none exists as part of its WAN – all provide critical communications capabilities that are needed now.[483]

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[475] *See* SCE's Response to TURN-SCE-026, Q.55, SA-3 Study.pdf, on Appendix A, pp. A-83 to A-85 and pp. A-105 to A-111.
[476] SCE-18, Vol. 6.
[477] *See* Exhibit TURN-06, pp. 85-86.
[478] *See* Exhibit TURN-06, pp. 51, 85-86, 90.
[479] *See* Exhibit SCE-18, Vol. 6, p. 16.
[480] *See* Exhibit TURN-06, p. 46.
[481] *See* Exhibit SCE-18, Vol. 10, p. 72.
[482] *See* Exhibit TURN-06, pp. 88, 89, and 91.
[483] *See* Exhibit SCE-18, Vol. 10, p. 12 (Figure I-1, describing SCE's integrated approach to Grid Modernization).

The FAN is a secure, Internet Protocol (IP)[484] based, data transmission system that enables information to be sent between the distribution automation devices on circuits to transmitters in substations, and then to the Grid Control Center. The FAN will replace the existing NetComm radio system, which is over 20 years old and at the end of its useful service life. The FAN will provide a modern wireless radio system capable of supporting the capacity, speed, connectivity, and security needs of existing and future distribution field devices and DERs for at least the next 15 to 20 years.[485]

During FAN deployment, SCE must continue to maintain the safety and reliability of the distribution grid. SCE's FAN deployment will take five years after the procurement, integration, and testing phases are completed due to the size of SCE's service territory and quantity of devices connected to our grid.[486] As such, SCE must also maintain the NetComm system until FAN is fully deployed and ready to replace it. The Distribution System Efficiency Enhancement Project (DSEEP) consists of servicing, maintaining and extending the useful life of our antiquated NetComm system until the FAN is fully deployed. The DSEEP request is based on the assumption that our FAN proposal will be approved in this GRC.

The CSP is a critical communications hub that enables a cyber-secure interface between the FAN and WAN. It also provides the underlying technology platform that enables remote management of substation functions.

Finally, the WAN is a fiber-optic high speed data highway that transmits data between the CSP and the Grid Control Center. Because of the data speed and data volume demands expected at many of our substations, existing substations that do not currently have fiber cable will now require WAN. Intervenors' proposals with respect to each of these technologies are insufficient.

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[484] Internet Protocol is the principal communications protocol or method by which data is sent from one computer to another over the internet. IP is the most widely adopted protocol used today to communicate information over communications networks.

[485] *See* Exhibit SCE-18, Vol. 10, Appendix A, pp. A-8 to A-55 (response to ED-SCE-002, Q.B.6).

[486] *See* Exhibit SCE-18, Vol. 10, p. 53.

4.10.7.1. Distribution System Efficiency Enhancement Project (DSEEP) is Only a Short-Term Solution; NetComm Must be Replaced by the FAN Immediately

ORA disputes the need for the FAN and recommends no funding, except for the $1.1 million recorded for 2016.[487] Instead, ORA supports continued funding for NetComm through DSEEP, but recommends reduced expenditures of $4.375 million in 2018 based on the average of 2014-2016 recorded expenditures. ORA suggests that SCE did not justify the cost increase to maintain the existing NetComm system.[488]

TURN rejects the need for FAN, believing that NetComm can continue to meet performance needs, including cybersecurity requirements.[489] Recognizing the "need to expand and secure the NetComm network," TURN recommends adding $0.6 million to upgrade NetComm (DSEEP) for 2018.[490] TURN presumes that the level of automation it proposes does not require FAN.[491]

The DSEEP program is designed to extend the life of NetComm until SCE can deploy FAN. Assuming adequate funding of DSEEP, which ORA does not even provide,[492] SCE can manage the performance degradation of NetComm beyond the saturation point until the FAN, as proposed in this GRC, is available. But SCE has explained the reasons why DSEEP is not a longer-term solution in lieu of FAN.[493]

First, SCE has shown that NetComm is reaching saturation. To achieve a modern grid, SCE must install more automation/telemetry devices, which will cause NetComm to reach saturation by the end of 2018.[494] NetComm is characterized by 2 minute latency and an average reporting frequency (the time lag for a distribution operator to receive information on the state of the system) of 15 minutes.[495] Intervenors argue that adding access points or data collection points (head-ends) to NetComm is sufficient to support continued growth in basic distribution automation.[496] At hearings, Mr. Gooding

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[487] *See* Exhibit ORA-09, pp. 114-116.
[488] *Id.*
[489] *See* Exhibit TURN-06, p. 80.
[490] *Id., p.* 81.
[491] *See* Exhibit TURN-06, p. 68.
[492] *See* Exhibit SCE-18, Vol. 10, p. 54, n. 169.
[493] *See* Exhibit SCE-18, Vol. 10, p. 54.
[494] *See* Exhibit SCE-02 Volume 10, pp. 75-76.
[495] *See* Exhibit SCE-18, Vol. 10, p. 54.
[496] *See* Exhibit TURN-06, p. 80; *see also* response to TURN-SCE-026 Q. 49, on Appendix A, p. A-138.

explained that adding access points can only improve reporting frequency (marginal network speed), but cannot increase the speed of the radios, which is a physical limitation.[497] More crucially, adding access points would not resolve NetComm's principal challenge, that it is nearing saturation.

Moreover, to achieve a shorter reporting frequency, SCE would need to use additional capacity, causing NetComm to reach saturation even sooner, regardless of any additional automation.[498] While additional investment is required to extend the useful life of the NetComm system,[499] every device added to NetComm after the saturation point will contribute to performance degradation on a network that is already very slow. This will reduce NetComm system reliability (and system operator visibility), at a time when grid reliability needs and increases in two-way power flows require more visibility and active management of the distribution system.[500]

In addition, the current NetComm system does not have sufficient, modern cybersecurity controls to adequately defend the distribution network from cyberattack in the current threat environment. SCE has upgraded elements in the NetComm system with select cybersecurity controls to protect the grid control center from a compromise of the NetComm radios.[501] SCE has also placed security controls around the central network management system used to operate NetComm. But the NetComm radios cannot be made secure.[502]

Finally, NetComm cannot enable all the capabilities of the DA devices proposed for SCE's Grid Modernization program. SCE has conducted several technology demonstrations as part of our EPIC-funded Integrated Grid Project.[503] SCE's tests and experience with NetComm and modern distribution automation clearly demonstrate that this old communications technology cannot support Grid Modernization. This is true even at the level of additional DA proposed by TURN.[504] NetComm lacks the necessary capacity, speed, reporting frequency, and cybersecurity controls. Replacing existing

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497 SCE, Gooding, Tr. 13/1722, lines 4-25.

498 *See* Exhibit SCE-18, Vol. 10, p. 54, including n. 168.

499 *See* WP SCE-02, Vol. 10, pp. 160-162, attached as Appendix B - Workpapers, pp. B-11 – B-13. ORA's recommended reduction in DSEEP based on 2014-2016 recorded expenditures does not provide sufficient funding to cover the proposed DSEEP scope of work. Increased costs for maintaining NetComm in 2017 and 2018 are directly related to increased volumes of field devices being deployed during these years. Failing to fully fund DSEEP would only exacerbate the vulnerabilities related to NetComm oversaturation.

500 *See* Exhibit SCE-18, Vol. 10, p. 54.

501 *See* Exhibit SCE-02 Vol. 10, p. 77.

502 *See* Exhibit SCE-18, Vol. 10 pp. 55-56, SCE, Tolentino, Tr. 12/1681; SCE, Gooding, Tr. 13/1726-27.

503 *See* Exhibit SCE-18, Vol. 10, p. 56.

504 *See* Exhibit SCE-18, Vol. 10A4, p. 43, Figure II-9, note 5.

NetComm communications infrastructure will take five years to deploy after procurement, integration, and testing phases.[505] Therefore, SCE needs to begin FAN deployment now.

4.10.7.2. SCE Cannot Rely on Third Party Networks in Lieu of FAN

SCE has also shown why SEIA-Vote Solar's suggestion to rely on existing and emerging third-party communications infrastructure[506] in lieu of SCE's FAN is untenable. SCE appreciates the need to use available infrastructure, where appropriate, to support its operational needs. For smaller DERs that do not provide time-critical grid reliability services, SCE will utilize the DER provider network over the public internet.[507] SCE has provided reasons why this solution is not viable for real-time grid management functions such as distribution automation that are critical for reliability, including: communication availability and reliability, service coverage, and lifecycle management.[508] SCE has proposed a balanced approach that leverages the public internet/third party networks for small DERs not participating in time-critical reliability services while also using a cost-effective FAN solution for real-time grid operations that meets the necessary requirements for critical reliability services.

4.10.7.3. Additional Funding is Needed to Support CSP

TURN recommends some funding for CSP, but at an insufficient level. TURN acknowledges the cybersecurity risk and the cybersecurity protection value CSP provides.[509] But to realize the full cybersecurity protection benefits, WAN and FAN are also needed. SCE's existing WAN infrastructure is only configured to support serial communications to and from the substation. If the CPUC adopts TURN's recommendation to implement the CSP, but not WAN, SA-3, or FAN, SCE would require additional funding for WAN (e.g., fiber terminals, IP routers, and switches) to enable IP connectivity to substations targeted for CSP deployment.[510]

CSP also requires certain facility upgrades included as part of SA-3, including the upgrade of the substation battery bank and battery charger unit to support the CSP's additional power requirements.[511]

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[505] *See* Exhibit SCE-18, Vol. 10, pp. 53, 58.
[506] *See* Exhibit SEIA-Vote Solar (Volkmann), p. 49-50.
[507] *See* Exhibit SCE-18, Vol. 10, Appendix A, p. A-139 (SCE's responses to ORA-SCE-181-TCR, Q.21) and Appendix A, p. A-136 (TURN-SCE-078, Q.06 a-d).
[508] *See* Exhibit SCE-18, Vol. 10 p. 57-58, including footnotes 176 and 177 on p. 58.
[509] *See* Exhibit TURN-06, p. 45.
[510] *See* Exhibit SCE-18, Vol. 10 p. 59.
[511] *Id.*

SCE would require incremental funding to support the necessary WAN infrastructure and proper housing needed for substation equipment, including the CSP. ORA recommends no funding for CSP because of its association with Grid Modernization.[512] Contrary to ORA's suggestion, it would be a mistake to delay CSP to await a decision in DRP Track 3. CSP is primarily about reliability and security.[513] The mitigation of current cybersecurity vulnerabilities that CSP provides is sufficient justification, regardless of the outcome of Track 3. CSP is the foundation for our cybersecurity between our centralized systems and field devices.[514] All of these features are only possible with the inclusion of the CSP.

4.10.7.4. Despite ORA's and TURN's Arguments, Funding for WAN is Needed Now

ORA recommends no WAN expenditures, except for the expenditures recorded in 2016.[515] ORA's recommendation is based on the lack of recorded costs for historical installation of new fiber optic cable from 2011-2015 and low amounts in 2016. ORA also argues that SCE's forecast expenditures to maintain its fiber optic network is unnecessary, given SCE's request for maintaining existing fiber optic cable included in Exhibit SCE-2, Vol. 7 and given the low 2011-2014 recorded costs.[516] ORA's reliance on a lack of historical WAN costs is illogical. For years, SCE has constructed fiber optic cable to meet the communications needs of substations through various projects that install new or upgrade substations.[517]

The funding cited by ORA that was included in SCE-02, Volume 7 is not sufficient for Grid Modernization purposes. That program is for maintaining existing telecommunications and fiber that has already been installed by SCE, and not for installing new fiber. Comparing recorded expenditures to maintain the existing fiber optic network with the forecast expenditures for installation of new fiber is not a like-for-like comparison. In contrast, SCE's Grid Modernization requires installing new fiber optic network communications to extend our fiber and IP network to substations that require SA-3, FAN, and

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[512] *See* Exhibit ORA-09, p. 117.
[513] *See* Exhibit SCE-18, Vol. 10, p. 14.
[514] *See* Exhibit SCE-18, Vol. 10 p. 59.
[515] *See* Exhibit ORA-09, p. 118.
[516] *See* Exhibit ORA-09, p. 118 ("Ex. SCE-2, Vol. 7 shows forecast expenditures of approximately $6.5 million a year to maintain its fiber optic network, which is nearly twice the recorded expenditures for 2011-2014.").
[517] For example, Distribution Substation Plan and Transmission Substation Plan projects included in SCE-02, Vol. 3R can include fiber cable installations.

CSP that do not currently have the required fiber and IP connections.[518] This WAN deployment began in 2016 and nearly all of the WAN expenditures will be incurred in 2017 and beyond.[519]

Although TURN recommends funding for CSP, it recommends no funding for WAN. TURN bases its position on its premise that "without grid operations automation, the FAN will not be needed, and that without automation, the FAN, or the SA-3, the WAN expansion will not be needed."[520] SCE has already explained why FAN is needed, independent of whether other Grid Modernization programs are adopted (*see* Section 4.10.7.1 and 4.10.7.2). SCE has also explained the importance of SA-3 (*see* 4.10.6). The WAN provides the network at the substations to enable the CSP, SA-3, and FAN to communicate and interoperate as well as the network connection to enable communications between the substations and our control centers.[521] The WAN also provides increased bandwidth to support the volume of data that will need to flow to and from the substation to support the operations and security of the CSP.[522] The WAN also hosts several critical controls that make up the overall Grid Modernization cybersecurity design.[523] The WAN uses a protocol that allows it to be segmented such that the breach of one segment does not compromise the others.[524] As stated in Section 4.10.7.3, if the CPUC adopts TURN's recommendation to implement the CSP, SCE would require funding for WAN to enable IP connectivity to substations targeted for CSP deployment.

4.10.8. Grid Management System

The GMS will provide the "brains" behind grid operations by analyzing data received from the DA and SA-3 equipment via the FAN, CSP and WAN, and then recommending optimum operator actions. The GMS is made up primarily of an Advanced Distribution Management System (ADMS) and DERMS.[525] The ADMS combines the features of SCE's existing Distribution Management System (DMS) and Outage Management System (OMS) and includes enhanced distribution and outage management functions necessary to support the capabilities outlined in the Grid Modernization

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[518] *See* SCE response to ORA-SCE-179-TCR, Q.37.a, on Appendix A, p. A-162.
[519] *See* Exhibit SCE-18, Vol. 10, p. 60.
[520] Exhibit TURN-06, p. 82.
[521] *See* Exhibit SCE 18, Vol. 10, p. 60.
[522] *See* Exhibit SCE 18, Vol. 10, pp. 60-61.
[523] *See* Exhibit SCE 18, Vol. 10, p. 61.
[524] *Id.*
[525] *See* Exhibit SCE-02, Vol. 10, pp.100-108 and Table III-13 on p. 106.

testimony.[526] The DERMS will enable real-time control and monitoring of DER, while operationalizing smart inverter functionalities into grid operations to support public policy goals. Although the GMS is designed to be an element in SCE's Grid Modernization program, the GMS provides great value to our customers even on its own.[527] SCE's BCA shows net reliability benefits from the GMS independent of the other Grid Modernization programs. Specifically, the GMS will provide analytical capabilities that will enable operators to restore power to unfaulted portions of a circuit in a third of the time. The benefit to cost ratio of the GMS is 4.9.[528]

As discussed in Section 4.10.2.4, ORA's recommendation that GMS be rejected simply due to its affiliation with Grid Modernization should be disregarded. Likewise, ORA's argument that GMS should be rejected on grounds of "the lack of recent expenditures" in GMS[529] makes no sense, insofar as ORA then recommends authorizing 2016 recorded expenditures of $2.257 million.[530]

ORA also criticizes SCE's proposal to replace the existing DMS and OMS systems with GMS, given that DMS and OMS were refreshed in 2016.[531] But SCE has explained that recent payments related to DMS were associated with completion payments of the last milestones and phases of the original DMS project, which began in 2013. These upgrades predated many of the regulatory and industry drivers for Grid Modernization, including integration of DERs.[532] Likewise, the OMS expenditures for 2016 and 2017 are related to the existing OMS refresh project, which is required to help ensure continuity of critical grid operations functions. Moreover, the vendor no longer supports the previous version of the OMS software, creating a significant operating risk.[533] The recent upgrades to DMS and OMS have proved useful and will continue to be needed during the planning, design and implementation phases of GMS. The GMS implementation will begin during the first quarter of 2019 and the ADMS will be implemented in the third quarter of 2019. The DMS/OMS can be decommissioned once the ADMS implementation is complete.[534]

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[526] *Id.*, Table III-13.
[527] *See* SCE-10, p. 111.
[528] *See* Exhibit SCE-18, Vol. 10A4, p. 67 and fn. 220.
[529] *See* Exhibit ORA-09, p. 119.
[530] *See* SCE-18, Vol. 10, p. 4.
[531] *See* Exhibit ORA-09, pp. 118-19.
[532] *See* Exhibit SCE-18, Vol. 10, p. 66 lines 21-22 through p. 67 lines 1-15; Appendix A, pp. A-171 to A-173, 176 (SCE response to TURN-SCE-052, Q3.b.ii,).
[533] *See* Exhibit SCE-18, Vol. 10, p. 66.
[534] *See* Exhibit SCE-18, Vol. 10, Appendix A, pp. A-124 to A-125.

The DMS/OMS lack the basic functionality needed for a modern grid.[535] TURN recognizes some of the limitations of SCE's current DMS and acknowledges that it is "not up to the task of supporting a distribution grid operated in the presence of high levels of DERs."[536] Nevertheless, TURN recommends against GMS in favor of adding ADMS and DERMS functionality onto SCE's existing DMS. TURN bases its recommended funding of $20M per year from 2018 to 2020 on a rough guess of the cost for ADMS and DERMS and welcomes SCE's "critique and input … to better hone this estimate."[537]

SCE appreciates TURN's desire to reduce costs through partial implementation of just the ADMS and DERMS. The main problem with TURN's proposal is that TURN assumes that its ADMS/DERMS proposal will cut the costs of the full GMS in half.[538] In fact, ADMS and DERMS represent 90% of the costs of the GMS, with ADMS costs alone making up 75% of the GMS costs.[539] At the same time, TURN's proposal excludes several important features of the GMS, including the Device Management System,[540] Adaptive Protection System,[541] and Integration Bus Technology.[542] These additional features provide benefits, such as adaptive and reconfigurable protection, and systems integration that provide a flexible, interoperable architecture to support future requirements without significant additional integration costs.

Instead of SCE's GMS, SEIA-Vote Solar recommends authorizing DERMS sufficient "to deploy the minimum technology necessary to satisfy the new DER communication requirements of Rule 21 while fully leveraging the monitoring, communication and control capabilities inherent in most DER technologies."[543] SEIA-Vote Solar's approach of replacing GMS with an upgraded DERMS will not work for all the reasons TURN's proposal will not. SEIA-Vote Solar's recommendation to forego ADMS is problematic, as ADMS provides a suite of applications required to integrate and optimize DERs into day-to-day grid operations, including grid state estimation.[544] OMS and DMS provide

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535 *See* SCE-02, Vol. 10 p. 106 (Table III-13: Required vs Existing GMS Functions).
536 *See* Exhibit TURN-06, p. 83.
537 *See* Exhibit TURN-06, p. 84.
538 *See* Exhibit TURN-06 p. 84.
539 *See* Exhibit SCE-18, Vol. 10 at p. 69 and Appendix B thereto (Workpapers, p. B-15); SCE, Gooding, Tr. 13/1731, lines 16-23.
540 *See* Exhibit SCE-18, Vol. 10 p. 68 lines 18-22.
541 *See* Exhibit SCE-18, Vol. 10 p. 68 lines 23-25 through p. 69 lines 1-2.
542 *See* Exhibit SCE-18, Vol. 10 p. 69 lines 3-7; Response to TURN-SCE-065, Q.19.a. on Appendix A, p. A-176.
543 *See* Exhibit SEIA-Vote Solar (Volkmann), p. 8.
544 Transcript Vol. 13, p. 1737-1742.

insufficient state estimation and must be replaced. With reverse power flow and load being masked by generation, operators without visibility along the circuit face the risk of relay tripping and equipment overload.[545] This is true any time operators make reconfiguration decisions on a circuit with DERs, and such routine reconfiguration decisions are made 22,000 times per year.[546] And as discussed in Section 4.10.4, these risks continue to exist when distributed generation is forced offline during an outage.[547] And while SEIA-Vote Solar claims that DERMS will help with situational awareness,[548] they also acknowledge that the improved visibility is only at the DER location, and will not bring back data from other grid devices located along the circuit.[549] Nor can the DMS be upgraded to provide these important features, as SCE's existing DMS hardware is reaching the end of its useful life and is no longer supported by the current vendor.[550]

4.10.9. SMT/DRPEP

The System Modeling Tool (SMT) is a set of software applications that will enable SCE engineers to perform more precise and near-real-time power-flow and capacity analyses of the electric system. The SMT replaces SCE's current capacity analysis software tools, which are inadequate because they require significant manual effort and rely on conservative assumptions that limit their precision and usefulness. The added functionality in SMT will facilitate capacity planning, interconnection studies, and the DRP's integrated capacity analysis.[551] The Distribution Resource Plan External Portal (DRPEP), will create an interactive website for customers and potential DER applicants to access current circuit interconnection capacities and locational net benefits analysis (LNBA) anywhere on SCE's distribution grid. DRPEP will be the public interface for SCE's ICA and LNBA results generated through SMT.[552]

ORA is the only intervenor that even comments on SMT and DRPEP. ORA questions why these projects were not included in SCE's IT volume and recommends no expenditures for 2017 and 2018

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[545] *See* Exhibit SCE-02, Vol. 10, p. 100, line 23 through p. 101, line 4.
[546] *Id.*
[547] *See* Exhibit SCE-02, Vol. 10, p. 101, lines 5-15.
[548] Transcript Vol. 20, p. 2847 lines 19-28.
[549] SEIA-Vote Solar, Volkmann, Tr. 20/2848 line 15 through 2849 line 6.
[550] *See* Exhibit SCE-18 Vol. 10, p. 67 lines 5-6 and n. 216.
[551] *See* Exhibit SCE-18 Vol. 10, p. 61.
[552] *See* Exhibit SCE-18 Vol. 10, p. 63.

because SCE included them in its Grid Modernization exhibit.[553] ORA provides no substantive rationale for rejecting either request.

SCE has provided ample evidence demonstrating the need for the SMT[554] and the DRPEP.[555] Both are needed for accurate system modeling[556] and to meet the ICA/LNBA requirements in the DRP.[557] As discussed in Section 4.10.2.4, ORA's blanket rejection of these projects simply because of their affiliation with Grid Modernization does not meet its burden in the face of SCE's showing and therefore SCE's request for these programs should be granted.

4.10.10. Grid Modernization O&M Expenses

SCE's proposed O&M expenses for Grid Modernization include costs for Organizational Change Management (OCM), grid modernization employee training, inspections of Programmable Capacitor Controls (PCC) for Distribution Volt/VAR Control, and establishment of a Program Management Office (PMO). SCE estimated specific needs based on the number of employees requiring training and consultant costs.[558]

ORA recommends $0 funding for O&M costs associated with the Grid Modernization activities due solely to their association with the DRP.[559] SEIA-Vote Solar adopted ORA's recommendation[560] and TURN does not provide testimony on O&M. For the reasons already stated in Section 4.10.2.4, this blanket rejection is inappropriate.

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[553] *See* Exhibit ORA-09, p. 120.

[554] *See* Exhibit SCE-02, Vol. 10 p. 85-96, SCE-18, Vol. 10, 61-63 and Appendix A, pp. A-83 to A-85 (SCE Response to TURN-SCE-026, Q.55 System Modeling Tool Study.pdf) and A-94 to A-99 (SCE Response to TURN-SCE-026, Q.55 SMT Study Calculations.xlsx).

[555] *See* Exhibit SCE-02, Vol. 10 p. 92-96, SCE-18, Vol. 10, at pp. 63-65 and Appendix A thereto at p. A-100 to A-104 (SCE response to TURN-SCE026, Q.55, on DRP External Portal Study.pdf, and DRPEP Avoided Labor Costs.xlsx).

[556] *See* Exhibit SCE-18, Vol. 10, p. 63, lines 9-13.

[557] *See* Exhibit SCE-18, Vol. 10, p. 62-63, *See also* R.14-08-013, *Proposed Decision of Commissioner Picker Decision On Track 1 Demonstration Projects A (Integration Capacity Analysis) And B (Locational Net Benefits Analysis)*, dated August 25, 2017.

[558] *See* Exhibit SCE-18, Vol. 10, p. 74 (Table III-12) for a forecast by activity.

[559] *See* Exhibit ORA-06, pp. 16-17 ("ORA recommends $0 funding for O&M costs associated with the Grid Modernization activities. All Grid Modernization costs should be reviewed and authorized by the Commission once the pending parallel proceedings related to the Grid Modernization proposal have reached a decision. Refer to Ex. ORA-09 for 16 ORA's explanations and discussion on Grid Modernization.").

[560] SEIA-Vote Solar does not specifically mention O&M, but generally agrees with ORA's Grid Modernization funding proposals.

If capital funding for Grid Modernization is approved, the related O&M is required to implement SCE's Grid Modernization plan. Technology alone will not determine the success of SCE's Grid Modernization program, but rather technology combined with the appropriate people and processes. Even TURN acknowledges that automation "only delivers benefits if the organization – including line employees such as grid operators – welcome the automation and enthusiastically embrace its use."[561] This highlights the importance of SCE's proposed OCM and training activities.

As discussed in SCE-18, Volume 11 (Grid Technology), SCE has moved the management of the DVVC program under SCE's Grid Modernization group. Even if the Commission adopts no O&M funding for new Grid Modernization programs, the DVVC O&M of $0.143 million should be tied to the approval of DVVC capital. That is, if the Commission adopts SCE's DVVC capital forecast, the related O&M should also be approved.

4.11. Grid Technology

SCE's Advanced Technology Division provides technology solutions that serve our customers' evolving needs and help us attain a number of state and federal policy goals while continuing to provide safe, affordable, reliable, and clean electricity to our customers. SCE applies a rigorous process to identify promising technologies, assess them for maturity and performance, test them for their intended purposes in simulated conditions, and then demonstrate or pilot them in a real-life grid environment before spending larger sums of money to deploy the technologies widely on the grid. Ultimately, our efforts here involve finding the right technology solutions and making sure those solution can actually be used across our grid without compromising safety and reliability.[562]

4.11.1. Energy Storage Pilots

SCE's proposed Energy Storage Pilots (ES Pilots) are capital programs that are intended to align with the Energy Storage Mandate, which permits utility ownership of up to 290 MW.[563] The ES Pilots will be deployed on the distribution system and actually used to provide electric service to SCE's customers.[564]

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[561] *See* Exhibit TURN-06, pp. 9-20.
[562] *See* Exhibit SCE-18, Vol. 11, p. 1, lines 3-15.
[563] *Id.* at pp. 9-10.
[564] *Id.* at p. 10, lines 1-2.

ORA has suggested that these Pilots violate a Commission order prohibiting investor-owned utilities from making research, development and demonstration (RD&D) proposals in GRCs. ORA believes that the ES Pilots should be proposed as part of the Electric Program Investment Charge (EPIC) technology demonstration and deployment (TD&D projects).[565] ORA's argument rests on the proposition that the ES Pilots qualify as TD&D projects and therefore must be requested and funded through EPIC. This is incorrect. In fact, the use of EPIC funding for the ES Pilots would actually run afoul of the criteria set down by the Commission.

Decision D.12-05-037 carefully defines an EPIC TD&D project as "the installation and operation of *pre-commercial* technologies or strategies."[566] This distinction between commercial and pre-commercial technologies is crucial. The energy storage technologies that SCE proposes to implement in the ES Pilots are already commercially available and will be used and useful through their service lives to provide electric service to our customers.[567] They will not be used to research or help develop pre-commercial technologies or solutions.[568] SCE provided uncontroverted evidence that the ES Pilot technologies that SCE is seeking funding for are commercially available.[569] Accordingly, purchasing such technologies with EPIC funding would actually violate the "pre-commercial" mandate the Commission set down in D.12-05-037.

SCE also cleared up any confusion over the terms "pilot" versus "TD&D project."[570] The two terms are not interchangeable, and ORA's attempt to conflate them is mistaken.[571] Finally, SCE exhaustively demonstrated that its ES Pilots do not unnecessarily duplicate efforts that are underway in SCE's own EPIC program and other proceedings.[572] For example, TURN had compiled a list of EPIC projects it felt were "likely duplicative" of other efforts. TURN offered no analysis supporting this assertion.[573] SCE provided a table that went through each project and clarified why it is not duplicative

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565 *See* ORA-09, pp. 125-126.
566 D.12-05-037, Ordering Paragraph No. 3 (emphasis added).
567 Exhibit SCE-18, Vol. 11, p. 11, lines 13-20.
568 *Id.* at p. 11, lines 19-20.
569 *Id.* at pp. 11-12.
570 *Id.* at pp. 12-13. SCE also pointed out how ORA's showing was internally contradictory on this point. Id at p. 14, lines 5-10.
571 *Id.*
572 *Id.* at pp. 14-19.
573 *See* Exhibit TURN-11, Table 5, pp. 11-12; SCE-18, Vol. 11, pp. 18-19.

of existing projects or capabilities.[574] SCE also showed that its ES Pilots met the criteria of the Commission's Energy Storage Mandate, explained how third-party ownership was considered, addressed cost-effectiveness questions, and illustrated how SCE is leveraging assets to maximize value for its customers.[575]

4.11.2. Advanced Technology Labs

TURN did not dispute any portion of SCE's Advanced Technology Labs request except the Equipment Demonstration & Evaluation Facility (EDEF). SCE has addressed the concerns the Commission previously raised about the EDEF in SCE's 2015 GRC. SCE conducted an in-depth survey of entities that were in the business of providing testing services similar to what SCE proposes to conduct at EDEF.[576]

SCE's exhaustive survey revealed that EDEF is the most cost-effective option, for a variety of reasons.[577] And EDEF permits SCE to perform its testing in a single, integrated environment at one physical location with conditions that replicate SCE's distribution grid conditions. This allows testing to be more accurate and useful.[578] SCE also showed why recovery of its EDEF costs should include recorded 2016 costs despite the Commission's guidance in the 2015 GRC.[579]

4.11.3. Distributed Volt VAR Control (DVVC) and Capacitor Automation

This program centralizes control of the field and substation capacitors so that SCE can coordinate and optimize voltage and VARs across all circuits that are fed by a substation. The program will reduce energy consumption and foster reliability by limiting voltage fluctuations.[580] The program should provide a 1% actual savings in energy costs for customers for every 1% reduction in voltage.[581]

ORA did not argue the merits of the DVVC program, but simply opposed it on the mistaken basis that DVVC must be a Grid Modernization effort (which ORA opposed in blanket fashion). SCE's

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[574] Exhibit SCE-18, Vol. 11, pp. 18-19.
[575] *Id.* at pp. 19-21.
[576] Exhibits SCE-02, Vol. 11, pp. 33-34; SCE-18, Vol. 11, pp. 6, 8-9.
[577] *Id.* at pp. 8-9.
[578] *Id.*
[579] Exhibits SCE-02, Vol. 11, pp. 31-32; SCE-18, Vol. 11, p. 9, lines 17-28. As indicated in SCE's rebuttal, SCE customers are already receiving benefits from the facility. *Id.*
[580] *See* Exhibit SCE-02, Vol. 11, pp. 45-46.
[581] *Id.* at p. 46, lines 9-13. *See* also Exhibit SCE-18, Vol. 11, p. 22, lines 6-12.

rebuttal showed why ORA is incorrect here.[582] SCE also clarified for ORA the relationship between the DVVC program and the Capacitor Automation program.[583] The DVVC will replace the Capacitor Automation program and offers substantial incremental benefits.[584]

4.12. Safety Training & Environmental Programs

In Exhibit SCE-02, Volume 12, SCE presents its direct testimony on its 2018 O&M forecast for (a) Transmission and Distribution (T&D) Safety and Training, and (b) Environmental Programs for Transmission and Distribution Assets.

Regarding T&D Safety and Training, SCE's O&M 2018 forecast is $62.081 million,[585] which was not challenged by any party[586] and which the Commission should adopt.

Regarding SCE's Environmental Programs for Transmission and Distribution Assets, SCE's 2018 O&M forecast is as follows:

- Environmental Programs – Distribution (Acct. 582.250): $2.012 million;[587]
- Environmental Programs – Transmission (Acct. 565.281): $4.608 million;[588]
- Hazardous Waste Management & Disposal - Distribution (Acct. 598.250): $3.551 million;[589] and
- Hazardous Waste Management & Disposal - Transmission (Acct. 573.250): $.246 million.[590]

ORA challenges SCE's forecast for (a) Environmental Program – Transmission (Acct. 565.281) and (b) Hazardous Waste Management & Disposal - Distribution (Acct. 598.250), which are discussed below.

4.12.1. Environmental Programs – Transmission (Acct. 565.281)

SCE records the environmental restoration and on-going maintenance cost for transmission-related projects in Account 565.281. SCE's 2018 forecast is $4.608 million, of which a small portion is

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582 Exhibit SCE-18, Vol. 11, pp. 23-24.
583 Exhibit SCE-18, Vol. 11, pp. 25-26.
584 *Id.* at pp. 26-27.
585 *See* Table I-1 in Exhibit SCE-02, Vol. 12, p. 2.
586 ORA's forecast and SCE's forecast differed by approximately $4000 due to ORA's proposed rounding adjustments in the RO model, which SCE agrees. *See* Exhibit SCE-29, p. 36.
587 *See* Figure II-3 in Exhibit SCE-02, Vol. 12, p. 25.
588 *See* Figure II-4 in Exhibit SCE-02, Vol. 12, p. 27.
589 *See* Figure II-5 in Exhibit SCE-02, Vol. 12, p. 31.
590 *See* Figure II-5 in Exhibit SCE-02, Vol. 12, p. 31.

for labor expenses ($356,000) while the overwhelming majority ($4.252 million) is for non-labor expenses.[591] SCE's 2018 labor forecast of $356,000 is based on the 2015 recorded expense of $135,000, plus an incremental increase of $221,000 for 3.1 full time employees needed due to increased construction and work activities.[592] For SCE's 2018 non-labor forecast of $4.252 million, similar to the methodology that SCE proposed and the CPUC approved in the 2015 GRC,[593] SCE developed a detailed, project-by-project cost estimate of the environmental restoration work needed for transmission projects that are currently undergoing restoration (e.g., TRTP), or forecast to come online during the test year and attrition years (i.e., 2018-2020),[594] and SCE based its 2018 non-labor forecast on an average of these years.[595]

In contrast to the CPUC-adopted methodology used by SCE, ORA proposes that the 2018 forecast be based on the last recorded year (2015). ORA incorrectly assumes that SCE's forecast includes deferred maintenance projects and programs that were included in SCE's 2015 GRC proceeding.[596] However, as explained by SCE witness Don Neal, under no circumstance is SCE asking for recovery twice for the same activity already funded in a prior rate case.[597] ORA's confusion may be due to the fact that transmission projects may be identified in multiple rate cases because a project can be delayed for a number of reasons, including licensing and construction delays.[598] However, as explained by Mr. Neal, there is no deferred maintenance since SCE is required to commence restoration activities as soon as a project closes.[599] Further, the fact that SCE's 2015 forecast of $2.546 million (2012 $) from the company's 2015 GRC came so close to SCE's 2015 recorded cost of $2.763 million ($2012 $) demonstrates that there was no deferred maintenance.[600] That is, even when transmission projects did not go online as scheduled, SCE still incurred additional environmental restoration costs for existing transmission projects or transmission projects not included in the original forecast.[601]

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591 *See* Figure II-4 in Exhibit SCE-02, Vol. 12, p. 27.
592 Exhibit SCE-02, Vol. 12, p. 28.
593 Exhibit SCE-02, Vol. 12, p. 28 (citing D. 15-11-021, pp. 282-283).
594 Exhibit SCE-02, Vol. 12, p. 28; Figure II-1 in Exhibit SCE-18, Vol. 12 A2, p. 6.
595 Exhibit SCE-02, Vol. 12, p. 28.
596 Exhibit ORA-07, pp. 37-38.
597 SCE, Neal, Tr. 14/1933.
598 SCE, Neal, Tr. 14/1932.
599 Exhibit SCE-18, Vol. 12, p. 6; SCE, Neal, Tr. 14/1933.
600 Figure II-1 in Exhibit SCE-18, Vol. 12 A2, p. 6; Exhibit SCE-18, Vol. 12, pp. 6-7.
601 Figure II-1 in Exhibit SCE-18, Vol. 12 A2, p. 6; Exhibit SCE-18, Vol. 12, pp. 6-7; SCE, Neal, Tr. 14/1934-1935.

ORA's forecast should also be rejected because ORA's testimony does not provide any evidence to support its contention that SCE's 2015 recorded expenses are representative of 2018 test year expenses. Indeed, they are not because transmission restoration project expenses depend on the number of active projects and the magnitude of restoration for each project. SCE is anticipating additional transmission projects during 2017-2019, such as the Falcon Ridge, Natural Substation, Santa Barbara Reliability, Valley Ivy Glen, and Alberhill projects.[602] As such, SCE's 2018 forecast should not be based on 2015 recorded costs (as proposed by ORA) because the 2018 forecast would then not include the actual environmental restoration work forecast for these and other projects identified in SCE's testimony.[603]

4.12.2. Hazardous Waste Management and Disposal (Acct. 598.250)

Waste Disposal services include lab expenses, the cost to remove and dispose equipment and material such as hazardous materials, universal waste, and transformers, and the cost for contractors to perform waste management activities.[604] Because hazardous waste management activity fluctuates from year-to-year and are reactive and unpredictable,[605] SCE's 2018 forecast of $3.551 million is based on a four-year average (2012-2015).[606] SCE excluded 2011 from the average due to the very large expense SCE incurred that year to perform waste clean-up after windstorms.[607]

The Commission should not adopt ORA's proposal to base the test year forecast on the last recorded year (2015).[608] Similar to ORA's testimony with respect to SCE's Account 565.281 for Transmission Environmental Programs, ORA incorrectly assumes that SCE's forecast improperly includes the cost of deferred projects.[609] And, similar to SCE's response to ORA's position on Transmission Environmental Programs, there is no deferred maintenance because SCE is not asking for recovery in the 2018 GRC twice for the same activity already funded from a prior GRC.[610] Further,

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602 Exhibit SCE-18, Vol. 12, p. 7.
603 Exhibit SCE-02, Vol. 12, p. 28; Figure II-1 in Exhibit SCE-18, Vol. 12 A2, p. 6.
604 Exhibit SCE-02, Vol. 12, p. 29.
605 For example, when SCE encounters a situation, such as when a crew reports debris in a right-of-way, SCE must respond as appropriate (e.g., testing soil, clearing the road) on a case-by-case situation based on the encounter. Exhibit SCE-18, Vol. 12, p. 9.
606 *See* Figure II-5 in Exhibit SCE-02, Vol. 12, p. 31; Exhibit SCE-02, Vol. 12, p. 30.
607 Exhibit SCE-02, Vol. 12, p. 30.
608 Exhibit ORA-07, pp. 40-41.
609 Exhibit ORA-07, pp. 41-42.
610 Exhibit SCE-18, Vol. 12, p. 10.

although ORA correctly indicates that SCE's 2011-2015 costs have been on a downward trend,[611] SCE does not believe that 2015 recorded costs are reflective of test year expenses. SCE's 2016 recorded costs dramatically increased to $3.916 million, which represents a 66% increase over 2015 recorded costs, due to variable costs such as lead paint remediation and transformer oil spill clean-ups.[612] The significant increase in 2016 recorded costs indicates a reversal of the downward trend. Fundamentally, ORA's proposal to forecast 2018 test year expenses based on 2015 recorded expenses (i.e., the lowest of the five years of recorded costs) should be rejected because it would not provide the funds SCE needs for waste management activities, including the compliance work that SCE must perform to dispose of hazardous and non-hazardous materials.[613]

4.13. Other Costs, Other Operating Revenues

In Exhibit SCE-02, Volume 13, SCE requests that the CPUC approve the Company's 2018 O&M request for T&D Other Costs of $130.943 million[614] and its 2018 revenue forecast for T&D Other Operating Revenue of $130.703 million.[615]

With respect to SCE's O&M request for T&D Other Costs, TURN takes issue with SCE's 2018 forecast for Underground Locating Service (Account 588.281), and ORA takes issue with SCE's 2018 forecast for Transmission & Distribution Work Order Write-Offs (Account 560.281 and 588.281) and Transmission/Substation and Distribution Capital-Related Expenses (Account 560.281 and 594.281).[616] In SCE's rebuttal testimony, because SCE agrees with TURN's downward adjustment of $363,000 for Underground Locating Service (Account 588.281),[617] SCE's revised 2018 O&M request for T&D Other Costs is $130.580 million.[618] Each of the foregoing areas of disagreement is addressed below.

No party disputes SCE's 2018 forecast for T&D Other Operating Revenue.

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[611] Exhibit ORA-07, p. 41.
[612] Exhibit SCE-18, Vol. 12, pp. 8-9.
[613] Exhibit SCE-18, Vol. 12, p. 8.
[614] *See* Table III-1 of Exhibit SCE-02, Vol. 13, p. 5, and Table I-2 of Exhibit SCE-18, Vol. 13A, p. 3.
[615] *See* Table III-19 of Exhibit SCE-02, Vol. 13, p. 41, and Table I-4 of Exhibit SCE-18, Vol. 13, p. 4.
[616] *See* Table I-2 of Exhibit SCE-18, Vol. 13A, p. 3.
[617] Exhibit SCE-18, Vol. 13, p. 14.
[618] That is, $130.943 million - $363,000 = $130.580 million.

4.13.1. Underground Locating Service (Account 588.281)

Underground locating service includes SCE's share of a regional notification center for calls related to locating underground facilities and marking underground facilities prior to excavation. SCE made an adjustment to its historical costs to reflect an accounting change commencing in 2015 when SCE began capitalizing the costs for underground locating service for SCE capital projects. SCE then used a five-year adjusted average to develop its 2018 forecast of $8.590 million.[619]

Because TURN believes that an adjustment should be made not only for the amounts that would have been capitalized (SCE's approach), but also the amounts that would have been expensed to accounts other than Account 588.281 through an allocation, TURN recommends a test year forecast of $8.227 million, which is $363,000 lower than SCE's 2018 forecast.[620] SCE accepts TURN's test year forecast of $8.227 million of Underground Locating Service expense.[621]

4.13.2. Transmission Work Order Write-Offs (Account 560.281) and Distribution Work Order Write-Offs (Account 588.281)

For Transmission Work Order Write-Offs (Account 560.281) and Distribution Work Order Write-Offs (Account 588.281), SCE uses a five-year average and forecasts $2.404 million and $7.389 million, respectively, for the 2018 test year. ORA proposes to use last year recorded (2015) for labor and non-labor for Account 560.281 resulting in a forecast of $966,000. ORA proposes to use last year recorded (2015) for labor and accepts a five-year average for non-labor resulting in a forecast of $6.490 million.[622]

Significantly, SCE's use of a five-year average to forecast 2018 test year expenses is the <u>same</u> methodology approved by the CPUC in SCE's <u>two prior</u> GRCs.[623] Indeed, the CPUC ordered SCE to use a five-year average in SCE's 2012 GRC after SCE proposed a different methodology.[624] While ORA notes that there has been a downward trend in cost, write-off costs are driven by factors primarily

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[619] Exhibit SCE-02, Vol. 13, pp. 24-25.
[620] Testimony of W. Marcus on behalf of TURN, p. 3. *See* also Table I-2 of SCE-18, Vol. 13A, p. 3.
[621] Exhibit SCE-18, Vol. 13, p. 14.
[622] *See* Table I-2 of Exhibit SCE-18, Vol. 13A, p. 3.
[623] *See* Table I-7 in Exhibit SCE-18, Vol. 13, p. 8.
[624] *See* D.12-11-051, pp. 289-293.

outside of SCE's control.[625] As such, the CPUC should continue to approve the use of a five-year average as proposed by SCE, and reject ORA's proposal to use the 2015 recorded year for work order write-offs.[626]

Using a five-year average, as proposed by SCE, results in an increase in labor expense over 2015 recorded, and thus ORA also objects to SCE's 2018 forecast because SCE "does not include any labor proposals for additional staff."[627] However, as explained by SCE witness Tracee Reeves, work order write-offs are not a component of a particular organization with people.[628] Rather, the labor cost in this activity is a flow-through of the cost classified as labor in work orders, and it is comprised of many bits and pieces of different individuals' time.[629] As such, requiring SCE to provide a staffing proposal is inappropriate for these accounts.

4.13.3. Transmission/Substation Capital-Related Expense (Account 560.281) and Distribution Capital-Related Expense (Account 594.281)

For Transmission/Substation Capital-Related Expense (Account 560.281) and Distribution Capital-Related Expense (Account 594.281), SCE forecasts $12.637 million and $40.725 million, respectively, for the 2018 test year. ORA forecasts $12.471 million and $34.923 million for these two accounts, respectively.[630] As discussed in more detail below, for both accounts, ORA disputes the methodology SCE uses to forecast 2018 test year expense. In addition, for distribution capital-related expense only, ORA disputes an adjustment SCE makes in the recorded years for Compatible Units.

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625 For example, given the long lead time for transmission/substation projects, changes can occur to the need, scope, and timing of third-party generation, customer loads, and other outside factors. *See* Exhibit SCE-18, Vol. 13, p. 6 for other examples.

626 *See* Table I-7 in Exhibit SCE-18, Vol. 13, p. 8. ORA proposes using the 2015 last year recorded for Transmission/Substation Work Order Write Offs and for the labor expenses for Distribution Work Order Write-Offs. For the 2018 non-labor expense for Distribution Work Order Write Offs only, ORA agrees with SCE's use of a five-year average. As indicated by SCE witness Tracee Reeves, labor and non-labor write-offs must be looked at in total and not broken apart, as the primary distinction between the two lies only whether the work represents time charged by SCE employees (which records as labor) or represents contractor charges, material, permits, etc. (which record as non-labor). *See* Exhibit SCE-18, Vol. 13, p. 7.

627 Exhibit ORA-07, p. 52, lines 19-20.

628 SCE, Reeves, Tr. 9/1195, line 18-1196, line 12. Exhibit SCE-18, Vol. 13, pp. 8-9.

629 SCE, Reeves, Tr. 9/1195, line 18-1196, line 12. Exhibit SCE-18, Vol. 13, pp. 8-9.

630 *See* Table I-2 of Exhibit SCE-18, Vol. 13A, p. 3.

4.13.3.1. SCE Is Using The Same Methodology Approved By The CPUC In SCE's Prior Rate Case, While ORA Is Using Inconsistent Historical Ratios

SCE uses three steps to develop the 2018 test year forecast for capital-related expense for transmission/substation and distribution capital-related expenses. SCE: (1) calculates a five-year weighted average of the historical ratio of total capital-related expense to total capital expenditures; (2) applies the historical ratio to the non-Pole Loading Program (non-PLP) capital expenditure forecast to calculate the forecast for Accounts 560.281 and 594.281; and (3) applies the same historical ratio to the PLP capital expenditure forecast to calculate the forecast for Accounts 571.125 and 593.125. While step three is not "mandated" by the CPUC,[631] as explained by SCE witness Tracee Reeves, SCE's aggregated approach is the methodology that the CPUC adopted and accepted in SCE's prior GRC.[632]

ORA's disaggregated approach uses inconsistent historical ratios. Using transmission/substation capital-related expense as an example,[633] the difference between SCE's aggregate approach and ORA's disaggregated approach is best illustrated in Table I-9 of SCE witness Tracee Reeves' rebuttal testimony:[634]

	Original Testimony			ORA Recommendation: Apply disaggregated rates only to non-PLP.			Results if ORA Methodology were used consistently: Apply disaggregated rates to non-PLP and PLP.		
	Non-PLP 560.281	PLP 571.125	Total	Non-PLP 560.281	PLP 571.125	Total	Non-PLP 560.281	PLP 571.125	Total
Calculated Rate	0.88%	0.88%		0.87%	0.88%		0.87%	6.87%	
Related Expense Forecast	$12,638	$199	$12,837	$12,471	$199	$12,670	$12,471	$1,550	$14,021
Net Change under ORA's Methodology				($167)	$0	($167)	($167)	$1,351	$1,184

Under SCE's aggregated approach, SCE calculated the historical ratio of 0.88% based on the total historical capital-related expense to total historical capital expenditures (both PLP and non-PLP).[635] SCE then uses the ratio of 0.88% to develop the expense forecast for both PLP and non-PLP. Since poles replaced under the PLP program are no different than poles replaced under the deteriorated pole

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631 SCE, Reeves, Tr. 9/1187, lines 6-8.
632 SCE, Reeves, Tr. 9/1187, line 17-1192, line 2. *See* also Exhibits SCE-32 and SCE-33.
633 SCE's analysis on transmission/substation capital-related expense applies to distribution capital-related expense as well.
634 Exhibit SCE-18, Vol. 13, p. 12.
635 Exhibit SCE-02, Vol. 13, p. 29.

program, the same historical ratio should be used to forecast capital-related expenses for both PLP and non-PLP.

In contrast, ORA uses the aggregated 0.88% historical ratio (which was developed based on both PLP and non-PLP historical capital-related expenses and capital expenditures) to develop the relatively small capital-related expense forecast for PLP only. ORA then uses a separate historical ratio (0.87%) based on non-PLP historical capital-related expense to non-PLP capital expenditures to develop the capital-related expense forecast for non-PLP.

Thus, ORA improperly and inconsistently uses an historical, aggregated ratio (based on both PLP and non-PLP historical capital-related expense) for PLP only forecast expenses. ORA intends to apply an historical, disaggregated ratio (0.87%) for non-PLP forecast expenses only. In order to be consistent, ORA would also need to apply an historical, disaggregated ratio (6.87%) for PLP forecast expenses as well.[636] SCE's methodology of using an historical ratio based on the total, aggregated portfolio level avoids disproportionate swings to the capital-related expense forecast that could occur if SCE were to use individual ratios.[637]

Given ORA's improper, inconsistent, and disproportionate application of the historical ratio between PLP and non-PLP expenses, the Commission should reject ORA's forecast methodology for transmission/substation and distribution capital-related expense.

4.13.3.2. ORA Improperly Seeks To Eliminate "Adjustments For Compatible Units" To SCE's Distribution Capital-Related Recorded Expenses

As seen on Table III-18, for Distribution Capital-Related Expense, SCE makes an "Adjustment for Compatible Units."[638] Due to implementation of a new compatible units methodology in 2018, SCE makes an adjustment in the recorded years.[639] ORA, however, opposes the historical adjustment since, according to ORA, the future costs related to the new methodology will be captured in SCE's next GRC.[640]

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[636] Exhibit SCE-18, Vol. 13, pp. 11-12.
[637] Exhibit SCE-18, Vol. 13, p. 11.
[638] Exhibit SCE-02, Vol. 13, p. 29.
[639] Exhibit SCE-02, Vol. 13, pp. 28-29.
[640] Exhibit ORA-07, pp. 48-49. ORA states: "This [the compatible unit adjustment] is a proposed methodology that SCE plans on implementing for future activities recorded to Account 594.281. If SCE implements this methodology in the TY, the costs and related activity performed under that new methodology will be

ORA's position is illogical and inconsistent. As explained by SCE witness Tracee Reeves, SCE's adjustment is necessary to align SCE's historical capital-related expense to reflect the expected expenses associated with implementing the compatible units methodology beginning in 2018.[641] Without making the adjustment, SCE's distribution capital-related expense forecast would be an "apples to oranges" comparison with the recorded expense.

Moreover, ORA is cherry picking and appears to only oppose adjustments which result in an upward adjustment to ratepayers. For example, in this instant case, with respect to distribution capital-related expense in the 2018 GRC, SCE's adjustment in the recorded years for compatible units results in additional recorded cost that is factored in the five-year average, which ORA opposes. Significantly, however, with respect to the same account (Distribution Capital-Related Expense) in the 2015 GRC, ORA did not oppose a similar adjustment (for the 4kV Cutovers), where SCE's adjustments resulted in a downward adjustment.[642] And, ORA did not oppose an adjustment to the 2011-2015 recorded years in the 2018 GRC associated with a future accounting change for Underground Locating Services, which also resulted in a downward adjustment.[643]

In summary, when there is a methodology change in the test year, SCE will make an adjustment in its GRC testimony in the recorded years, for forecasting purposes, to avoid an apples-to-oranges comparison between the recorded years and the forecast year. SCE made such an adjustment in the recorded years for the 4kV Cutovers in the Distribution Capital-Related Expense in the 2015 GRC, which the CPUC adopted, and has likewise done so for the Compatible Units in the Distribution Capital-Related Expense and the Underground Locating Services in the 2018 GRC. This is a normal and accepted practice and should be adopted regardless of whether such an adjustment results in an upward or downward adjustment to the test year forecast.

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captured and demonstrated in SCE's next GRC. ORA removed SCE's Adjustment for Compatible Units from its TY estimate of $34.923 million for Account 594.281." *Id.* at p. 49.

641 Exhibit SCE-18, Vol. 13, p. 16.

642 There is no reference in ORA's testimony on distribution capital-related expense of ORA opposing the adjustment SCE made for the 4kV cutover. Also, the CPUC's decision did not propose any changes. *See* 2015 GRC SCE-03, Vol. 10, Table I-8, p. 28; Section 7.11.4 of Decision 15-11-021, and Exhibits 118 and 119.

643 *See* Table III-15, p. 26 of Exhibit SCE-02, Vol. 13.

4.14. Additional Issues

5. CUSTOMER SERVICE

SCE's Customer Service organization assists SCE's customers, served through over 5 million service accounts, by educating them about how their energy usage impacts their bills, responding to their requests for service, billing them in a timely and accurate manner, and addressing their questions and concerns.[644] SCE provides customer service in a safe, effective, and affordable manner, while supporting state and federal energy policy goals that rely on customer participation.[645] SCE has demonstrated the reasonableness of its request to continue to provide appropriate customer service, particularly as technology and customer needs and expectations advance. The Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and other intervenors base their recommendations for reductions on incorrect facts, assumptions, or analyses and fail to support their proposals with record evidence. The Commission should approve SCE's reasonable and justified request for the Customer Service organization.

5.1. Customer Service – O&M

For Test Year 2018, SCE forecasts $198.690 million (constant 2015 $) in operation and maintenance (O&M) expenses for Customer Service.[646] This request is $9.25 million *below* SCE's 2015 recorded adjusted base. This forecast reflects $23.85 million of reductions that more than offset Customer Service's proposed program changes, including O&M costs related to SCE's proposed Customer Service (CS) Re-Platform project. SCE forecasts $8.90 million expense and $1.75 million benefits, for a total $7.15 million in O&M costs related to CS Re-Platform.[647]

5.1.1. TURN's Recommendation to Eliminate Customer Growth Is Unjustified

The cost of many activities in Customer Service are directly related to the number of customers that SCE serves. As the number of customers increases, the level of activities increases and, therefore, costs increase. The Commission has recognized this fact consistently in past GRCs. TURN, however, recommends eliminating customer growth adjustments across FERC accounts where customer growth

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[644] Exhibit SCE-03R, p. 1.
[645] Exhibit SCE-03R, p. 1.
[646] Exhibit SCE-03RA2, p. 8.
[647] Exhibit SCE-03RA2, p. 9.

has a demonstrated direct impact on the cost of Customer Service operations. TURN's recommendation relies on incorrect assumptions, is contrary to Commission precedent, and should be rejected.

TURN states that "customer growth appears not to be an explicit driver for the upward trend in the forecast."[648] TURN bases its recommendation on 2016 recorded/unadjusted expenses that were below what SCE forecast for that year. Specifically, TURN states that SCE's Customer Service "expenses were below those forecast for 2016 by five percent in metering, and by about one percent in in the billing and customer contact areas."[649] TURN also relies on lower activity levels in 2016 than in 2015 in the customer contact center, payment, and metering services areas.[650] TURN is incorrect. TURN's analysis relies on simplistic and incomplete comparisons and does not in any way demonstrate that customer growth is not a valid and significant driver for Customer Service activities and costs. As discussed in more detail below, TURN relies on unadjusted recorded data and only select comparisons of Customer Service transaction volumes.[651] Comparing 2015 recorded adjusted data to 2016 recorded unadjusted data and failing to consider the full range of Customer Services activities that are directly impacted by the number of customers SCE serves is inappropriate.

TURN also fails to recognize that SCE's continuing productivity improvements and cost pressures driven by customer growth are not mutually exclusive. Operational excellence efforts offset cost drivers, including customer growth.[652] As such, these savings are reflected in SCE's forecast, which may obscure, but does not negate, the existence of customer growth that increases costs by increasing the number of meters to be read, the number of bills to be processed, the number of customer calls and inquiries to be handled, and the number of meters to be tested and replaced.[653] In fact, in 2016, SCE experienced customer growth of 0.54 percent over 2015, and SCE expects to achieve its overall customer growth forecast of 2.26 percent from 2015 to the 2018 Test Year.[654] This customer growth will create real costs in the Customer Service organization.[655]

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[648] Exhibit TURN-03, p. 10.
[649] Exhibit TURN-03, p. 10.
[650] Exhibit TURN-03, p. 10.
[651] Exhibit SCE-19, p. 4-5.
[652] Exhibit SCE-19, p. 4-5.
[653] Exhibit SCE-19, p. 5.
[654] Exhibit SCE-19, p. 6.
[655] Exhibit SCE-19, p. 5.

TURN is not the first intervenor to challenge customer growth as a driver of Customer Service costs, but the Commission has consistently rejected these challenges.[656] In SCE's 2009 and 2012 GRCs, the Commission adopted customer growth adjustments as a reasonable approach to forecasting Customer Service costs. In SCE's 2009 GRC, the Commission found that "SCE's methodology is reasonable in adjusting recorded costs to reflect productivity and forecasting the cost effects of additional customer growth. Thus, we adopt SCE's revised estimates as reasonable for those expenses affected by customer growth."[657] The Commission approved a customer growth adjustment using this same method in SCE's 2012 GRC.[658] The Commission also approved SCE's uncontested customer growth adjustment in SCE's 2015 GRC.[659] TURN has provided no evidence to demonstrate that the Commission should deviate from its precedent. Thus, the Commission should reject TURN's recommendation to eliminate SCE's proposed customer growth adjustments.

5.1.2. SCE's Forecast for its Metering Services Organization Is Appropriate

SCE's forecast for its Metering Services Organization (MSO) is appropriate and the Commission should reject TURN's request for reductions based on eliminating the adjustment for forecast customer growth. As discussed above, TURN's argument relies on inappropriate assumptions and is contrary to Commission precedent. SCE has demonstrated that customer growth directly impacts MSO's costs.

5.1.2.1. Meter Reading Operations – FERC Account 902

SCE bases its $10.165 million forecast in FERC account 902[660] on 2015 recorded adjusted expenses of $11.334 million. SCE adjusted this base cost to include $256,000 in customer growth and remove $1.425 million in savings achieved by reducing manual meter reads for Opt-Out customers to every other month, rather than monthly.[661] TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $256,000.[662] Neither ORA nor any other intervenors propose

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656 *See* D.09-03-025, pp. 103-104; D.12-11-051, pp. 309-310.
657 D.09-03-025, p. 104.
658 D.12-11-051, pp. 309-310 (approving SCE's customer growth adjustments as a cost driver, although reducing the overall customer growth forecast).
659 D.15-11-021, p. 190.
660 FERC Account 902 includes the costs incurred by the meter services group that manages, collects, and records meter-usage data needed to bill customers and enable their participation in energy management programs and services.
661 Exhibit SCE-19, p. 10.
662 Exhibit TURN-03, p. 11.

any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reduction.

TURN bases its proposed reduction on the fact that 2016 recorded unadjusted costs were lower than forecast for that year, alleging that customer growth therefore appears not to drive costs in this FERC account.[663] TURN is incorrect. The estimated increase of 113,513 customers will directly impact MSO's costs in this area. For example, SCE will need to add resources to read customer meters, initiate over-the-air turn ons and turn offs, initiate disconnects and reconnects, handle basic work requests, optimize the meter communication network and operations to improve system performance, provide over-the-air storm support and outage management, among other network activities.[664] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's forecast for FERC Account 902.

5.1.2.2. Test, Inspect, and Repair Meters – FERC Account 586.400

SCE bases its $15.512 million forecast in FERC account 586.400[665] on 2015 recorded adjusted expenses of $16.075 million. SCE adjusted this base cost to include $362,000 in customer growth and remove $637,000 in savings for repair meter testing and $289,000 in savings from CS Re-Platform benefits.[666] TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $362,000.[667] TURN also recommends reducing SCE's forecast for test and inspect meters activity by $1.010 million (although TURN offers to offset this reduction by adding back $25,000 from operational excellence cost reductions).[668] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reductions.

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[663] Exhibit TURN-03, pp. 10-11.
[664] Exhibit SCE-19, p. 11.
[665] FERC Account 586.400 includes the costs related to SCE's Electrical Metering Services (EMS), Engineering and Meter Shop operations, and field maintenance and repair of electric billing and load survey meters.
[666] Exhibit SCE-19, p. 12.
[667] Exhibit TURN-03, p. 13.
[668] Exhibit TURN-03, p. 13.

TURN bases its proposal to eliminate the customer growth adjustment solely on an observed decline in 2016 activity levels for the "field test and inspect" activity, alleging that customer growth therefore appears not to drive costs in this FERC account.[669] TURN is incorrect. TURN's limited analysis does not consider other activities driven by customer growth that will directly impact MSO's costs in this area. For example, sample and routine meter test volume increased over 22 percent from 2015 to 2016.[670] Meter installation tests also increased over 12 percent during this period. As more meters are added to support customer growth, workload and associated costs will increase for testing, inspecting, repairing, and maintaining meters.[671] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's proposed adjustment of $362,000 for customer growth in FERC Account 586.400.

TURN supports its proposal to reduce the test and inspect meters activity by $1.010 million by observing that the number of tests requested declined from 2015 to 2016.[672] TURN's analysis, however, inappropriately compares 2016 recorded unadjusted costs to 2015 recorded adjusted costs. This comparison fails to acknowledge the 2015 adjustment of $1.5 million in costs from FERC Account 901 for certain support activities. This same adjustment of approximately $1.5 million would have been made to the 2016 data if it were presented on an adjusted basis, which is necessary for an appropriate comparison.[673] Further, TURN's analysis fails to consider other activities recorded in FERC Account 586.400, including the meter shop test and inspect and repair meters functions. When 2016 recorded adjusted data is viewed for all key activities in this FERC Account, SCE's recorded adjusted costs actually exceed its forecast for that year.[674] Because TURN's analysis is flawed and a corrected analysis supports SCE's request, the Commission should reject TURN's proposed $1.010 million reduction in FERC Account 586.400.

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[669] Exhibit TURN-03, pp. 10, 12.
[670] Exhibit SCE-19, p. 13.
[671] Exhibit SCE-19, p. 13.
[672] Exhibit TURN-03, p. 12.
[673] Exhibit SCE-19, pp. 13-14.
[674] Exhibit SCE-19, pp. 14-15.

5.1.2.3. Turn-On and Turn-Off Services – FERC Account 586.100

SCE bases its $4.875 million forecast in FERC account 586.100[675] on 2015 recorded adjusted expenses of $5.050 million. SCE adjusted this base cost to include $114,000 in customer growth and remove $289,000 in savings from CS Re-Platform benefits.[676] TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $114,000.[677] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reduction.

TURN bases its proposed reduction on the fact that 2016 activity levels were lower than forecast for that year, alleging that customer growth therefore appears not to drive costs in this FERC account.[678] TURN is incorrect. The estimated increase of 113,513 customers will directly impact MSO's costs in this area. Although manual turn-on activities fell in 2016, they fell by less than one percent, which is considered steady.[679] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. In past GRCs, SCE forecast saving $8.7 million in this specific FERC Account from these efforts.[680] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's forecast for FERC Account 586.100.

5.1.2.4. Customer Installation and Energy Theft Expense – FERC Account 587

SCE bases its $6.932 million forecast in FERC account 587[681] on 2015 recorded adjusted expenses of $6.779 million. SCE adjusted this base cost to include $153,000 in customer growth.[682] TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of

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675 FERC Account 586.100 includes the costs related to field resources used for customer-requested turn-on and turn-off services that are not energized or de-energized through the remote service switch (RSS).
676 Exhibit SCE-19, p. 15.
677 Exhibit TURN-03, p. 13.
678 Exhibit TURN-03, pp. 10, 13.
679 Exhibit SCE-19, pp. 16-17.
680 Exhibit SCE-19, p. 17.
681 FERC Account 587 includes the labor costs related to customer installation, energy theft, and field services management and supervision.
682 Exhibit SCE-19, p. 17.

$153,000.[683] TURN also recommends using 2016 as the base year for pick-up reads and exception orders.[684] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reductions.

TURN bases its proposal to eliminate the customer growth adjustment solely on an observed decline in 2016 pick-up reads and exception orders, alleging that customer growth therefore appears not to drive costs in this FERC account.[685] TURN is incorrect. TURN fails to recognize that certain meter installations, energy theft, and a mandatory annual survey of smart meter installations are driven by customer growth and will directly impact MSO's costs in this area.[686] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's proposed adjustment of $153,000 for customer growth in FERC Account 587.

TURN recommends using 2016 recorded unadjusted data as the base for forecasting expenses because pick-up reads and exception orders declined from 2015 to 2016.[687] TURN's analysis, however, inappropriately compares 2016 recorded unadjusted costs to 2015 recorded adjusted costs. Further, TURN's analysis fails to consider other activities recorded in FERC Account 587, including energy theft and supervisory activities. Energy theft investigations increased from 2015 to 2016.[688] Because TURN's limited review fails to acknowledge increases in other activities that record to this FERC Account, the Commission should reject TURN's proposal to use 2016 recorded unadjusted costs as the base for forecasting costs in FERC Account 586.400.

5.1.2.5. Meter Services Operations and Management – FERC Account 580

SCE bases its $4.869 million forecast in FERC account 580[689] on 2015 recorded adjusted expenses of $5.277 million. SCE adjusted this base cost to include $155,000 in customer growth and

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[683] Exhibit TURN-03, p. 14.
[684] Exhibit TURN-03, p. 14.
[685] Exhibit TURN-03, pp. 10, 14.
[686] Exhibit SCE-19, pp. 18-19.
[687] Exhibit TURN-03, p. 14.
[688] Exhibit SCE-19, pp. 19.
[689] FERC Account 580 includes labor costs for Customer Service safety, safety field operations, and safety support and training.

remove $1.181 million in savings achieved through operational excellence initiatives.[690] TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $155,000.[691] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reduction.

TURN bases its proposed reduction on the fact that 2016 recorded unadjusted costs were lower than forecast for that year, alleging that customer growth therefore appears not to drive costs in this FERC account.[692] TURN is incorrect. TURN solely relies on SCE's $600,000 cost reduction in 2016 and fails to demonstrate that customer growth will not directly impact MSO's costs in this area.[693] In fact, the activities recorded to this FERC Account support meter and field-related services that are driven by customer growth.[694] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $1.181 million in this specific FERC Account from these efforts by 2018, so it is unsurprising that SCE's costs in 2016 were below its forecast.[695] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's forecast for FERC Account 580.

5.1.3. SCE's Forecast for its Revenue Services Organization Is Appropriate

SCE's forecast for its Revenue Services Organization (RSO) is appropriate and the Commission should reject TURN's request for reductions based on eliminating the adjustment for forecast customer growth. As discussed above, TURN's argument relies on inappropriate assumptions and is contrary to Commission precedent. SCE has demonstrated that customer growth directly impacts RSO's costs. TURN and ORA make additional recommendations for adjustments to RSO's forecast, which should also be rejected, for the reasons discussed below.

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690 Exhibit SCE-19, p. 20.
691 Exhibit TURN-03, p. 15.
692 Exhibit TURN-03, pp. 10, 15.
693 Exhibit TURN-03, p. 15.
694 Exhibit SCE-19, p. 21.
695 Exhibit SCE-19, p. 21.

5.1.3.1. Billing Services – FERC Account 903.500[696]

SCE bases its $27.084 million forecast in FERC account 903.500[697] on 2015 recorded adjusted expenses of $27.420 million. SCE adjusted this base cost to include $619,000 in customer growth, $1.886 million for program changes (including policy adjustments, service guarantees, net energy metering (NEM), and community choice aggregator (CCA) programs), and $1.760 million for CS Re-Platform expenses. SCE also adjusted the base cost to remove $4.178 million in savings achieved through operational excellence initiatives and $423,000 in CS Re-Platform benefits.[698]

ORA recommends eliminating SCE's requested $249,000 to establish a base level of service guarantee credits as a normal cost of doing business.[699] TURN supports ORA's recommendation.[700] Neither ORA nor TURN, however, provide a basis for this recommendation beyond noting that the Commission has rejected similar requests in the past.[701] SCE's request to establish a baseline level of service guarantee credits, rather than pay the incremental costs necessary to achieve perfect performance, is cost-effective and reasonable. It would be cost-prohibitive to develop and implement a system that ensured 100 percent attainment of SCE's service standards. With SCE's service guarantee program, customers receive a timely and accurate first bill 99.3 percent of the time, and only 4.8 percent of turn-on and billing-inquiry appointments result in a service guarantee payment.[702] Recovering the costs for this basic level of service from customers is appropriate because all customers benefit from this quality standard. Approving SCE's request to recover these costs through rates will not reduce SCE's incentive to maintain this quality standard, because shareholders will be required to pay for any service guarantees that exceed the authorized base levels.[703] Because neither ORA nor TURN present a

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696 ORA recommends denying SCE's requested $2.833 million in CS Re-Platform staff augmentation costs and allowing SCE to track those costs in a memorandum account and seek recovery through an advice letter. Exhibit ORA-12, p. 18. TURN supports this recommendation. Exhibit TURN-03, p. 19. SCE addresses this issue in its discussion of CS Re-Platform in Section 6.3 of this brief.

697 FERC Account 903.500 includes costs for the organization that provides timely and accurate billing for SCE's customers, including managing, maintaining, and supporting the customer usage and billing processes and program operations.

698 Exhibit SCE-19, p. 22.

699 Exhibit ORA-12, p. 16.

700 Exhibit TURN-03, p. 16.

701 *See* Exhibit ORA-12, p. 16; Exhibit TURN-03, p. 16.

702 Exhibit SCE-19, pp. 23-24.

703 Exhibit SCE-19, p. 23.

reasonable basis for rejecting SCE's proposal to include a normal base level of service guarantees in rates, the Commission should approve SCE's request.

TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $619,000.[704] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for customer growth, and the Commission should reject TURN's proposed reduction. TURN bases its proposed reduction on the fact that 2016 recorded unadjusted costs were 2 percent lower than forecast for that year, alleging that customer growth therefore appears not to drive costs in this FERC account.[705] TURN is incorrect. TURN fails to demonstrate that customer growth will not directly impact RSO's costs in this area. In fact, the billing-related activities recorded to this FERC Account are driven by customer growth.[706] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $4.178 million in this specific FERC Account from these efforts by 2018, so it is unsurprising that SCE's costs in 2016 were below its forecast.[707] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's customer growth forecast for FERC Account 903.500.

TURN recommends removing NEM expenses from SCE's policy adjustment forecast, which would reduce SCE's forecast by $40,000.[708] TURN bases its recommendation on the fact that SCE does not expect these expenses to recur.[709] Although SCE does not expect this specific issue to recur, SCE has demonstrated that different anomalous or unique events can result in higher costs, as happened in 2012 and 2015.[710] It is reasonable to assume that other unique events could occur, creating large variation from year-to-year. SCE's proposal to use a five-year average to forecast policy adjustment costs is an appropriate method to address year-to-year variations. Using a five-year average appropriately forecasts for these occasional anomalies. Neither ORA nor any other intervenor

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[704] Exhibit TURN-03, p. 16.
[705] Exhibit TURN-03, pp. 10, 16.
[706] Exhibit SCE-19, p. 25.
[707] Exhibit SCE-19, p. 26.
[708] Exhibit TURN-03, p. 16.
[709] Exhibit TURN-03, p. 16.
[710] Exhibit SCE-03R, pp. 77-78.

recommended changing SCE's policy adjustment forecast. Thus, the Commission should reject TURN's recommendation to exclude NEM expenses from the forecast.

TURN also recommends rejecting SCE's forecast of $568,000 for NEM application processing. TURN bases its recommendation on the fact that NEM application volumes did not increase from 2015 to 2016.[711] SCE acknowledges a slight downturn in NEM applications in 2016, but TURN's analysis fails to account for steady increases projected in 2017, 2018, 2019, and 2020.[712] The slight decrease in 2016 was explained primarily by regulatory affects that are not expected to affect the forecast increase in applications going forward.[713] TURN's analysis also fails to account for applications requiring specialized handling, which increased from 11 percent in 2015 to 23 percent in 2016. SCE expects applications requiring special handling to continue to grow under the new NEM successor tariff.[714] Neither ORA nor any other intervenor recommended changing SCE's NEM application processing forecast. For these reasons, SCE's forecast is reasonable and the Commission should reject TURN's recommendation.

TURN also recommends reducing SCE's forecast in FERC Account 903.500 by $300,000 in non-labor expenses by adding three million e-bills to SCE's forecast.[715] SCE, however, carefully forecast e-billing enrollments during this GRC period on planned marketing campaigns and default enrollment initiatives, and forecast $1.2 million in savings associated with these efforts through 2018.[716] TURN incorrectly alleges that SCE did not assume e-bill savings in 2019 or 2020.[717] In fact, SCE does forecast savings related to e-billing to continue through these years.[718] TURN offers no evidence that SCE's forecast is incorrect or that additional e-billing enrollments will occur beyond those forecast by SCE. Neither ORA nor any other intervenor recommended changing SCE's forecast for e-billing enrollments. The Commission should reject TURN's unsupported recommendation.

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[711] Exhibit TURN-03, pp. 17-18.
[712] Exhibit SCE-19, p. 27.
[713] SCE, Kempf, Tr. 13/1897-1898.
[714] Exhibit SCE-19, pp. 27-28.
[715] Exhibit TURN-03, p. 19.
[716] Exhibit SCE-19, p. 28.
[717] Exhibit TURN-03, p. 18.
[718] Exhibit SCE-19, p. 28.

5.1.3.2. Credit and Payment Services – FERC Account 903.200[719]

SCE bases its $16.125 million forecast in FERC account 903.200[720] on 2015 recorded adjusted expenses of $16.348 million. SCE adjusted this base cost to include $368,000 in customer growth and $333,000 for CS Re-Platform expenses. SCE also adjusted the base cost to remove $871,000 in savings achieved through operational excellence initiatives and $53,000 in CS Re-Platform benefits.[721]

TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $368,000.[722] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for customer growth, and the Commission should reject TURN's proposed reduction. TURN bases its proposed reduction on the fact that 2016 recorded unadjusted costs were lower than forecast for that year, alleging that customer growth therefore appears not to drive costs in this FERC account.[723] TURN is incorrect. TURN fails to demonstrate that customer growth will not directly impact RSO's costs in this area. In fact, the credit and payment activities recorded to this FERC Account are driven by customer growth.[724] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $871,000 in this specific FERC Account from these efforts by 2018, so it is unsurprising that SCE's costs in 2016 were below its forecast.[725] For example, SCE's initiatives successfully migrated customers from high-cost payment channels to lower-cost payment channels, but that does not mean that customer growth will not impact RSO's costs overall.[726] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method

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[719] ORA recommends denying SCE's requested $333,000 in CS Re-Platform staff augmentation costs and allowing SCE to track those costs in a memorandum account and seek recovery through an advice letter. Exhibit ORA-12, pp. 20-22. TURN supports this recommendation. Exhibit TURN-03, p. 21. SCE addresses this issue in its discussion of CS Re-Platform in Section 6.3 of this brief.

[720] FERC Account 903.200 includes expenses related to credit policy development and enforcement, customer verification, fraud prevention, customer risk assessment, collection activities, and the management of credit-related operations to minimize arrearages and uncollectible expense.

[721] Exhibit SCE-19, pp. 28-29.

[722] Exhibit TURN-03, p. 21.

[723] Exhibit TURN-03, pp. 10, 21.

[724] Exhibit SCE-19, p. 30.

[725] Exhibit SCE-19, pp. 30-31.

[726] Exhibit SCE-19, p. 31.

of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's customer growth forecast for FERC Account 903.200.

TURN also recommends reducing SCE's forecast by $1.005 million based on 2016 recorded unadjusted data for payment services. Neither ORA nor any other intervenor recommended changes to SCE's forecasting method for payment services. TURN bases its recommendation on the fact that costs for payment services have declined over the last five years because fewer customers are paying bills by mail, at payment agencies, or at local offices.[727] TURN's recommendation relies on unadjusted costs, which are not appropriate for forecasting.[728] TURN also fails to recognize that payment services activities do not represent the activities for the entire FERC Account. SCE properly forecast the costs for this FERC Account, including productivity gains that may have been realized in the payment services area earlier than anticipated.[729] TURN also fails to note that the largest cost decreases in this FERC Account occurred from 2011 to 2012, while they remained stable from 2014 to 2015, the last year for which SCE has recorded adjusted data.[730] Reviewing the trends in historical recorded adjusted costs shows that using 2015 recorded adjusted costs is an appropriate forecasting method for this FERC Account. Further, this method is supported by Commission precedent.[731] For these reasons, the Commission should reject TURN's recommendation and approve SCE's forecasting method.

For SCE's next GRC, Consumer Federation of California (CFC) recommends that the Commission require SCE to (1) provide an analysis of the relationship between rate increases, arrearages, and disconnections, and (2) show that disconnections are not unjustifiably biased toward any district or other customer group as the result of limited SCE resources.[732] SCE agrees to work with CFC and other stakeholders to develop a report, to be included as part of its next GRC, that analyzes the relationship between rate increases, arrearages, and disconnections, if any. It may not be possible, however, to isolate the effects of a single factor, such as a rate increase, on arrearages and disconnections.[733] CFC's second recommendation, that SCE show its disconnection practices are unbiased, is unnecessary. SCE's disconnection practices comply with SCE's Commission-approved

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[727] Exhibit TURN-03, pp. 19-21.
[728] Exhibit SCE-19, p. 31.
[729] Exhibit SCE-19, p. 31.
[730] Exhibit SCE-19, p. 32.
[731] D.89-12-057, 34 CPUC2d 1999.
[732] Exhibit CFC-03, p. 7.
[733] Exhibit SCE-19, p. 32.

tariffs, including Rule 8 and Rule 11, which govern required notices and disconnection processes and prohibit discrimination based on customer location, group, or class. Further, SCE's Commission-approved disconnection practices comply with Public Utilities Code § 453, which states that "[n]o public utility shall establish or maintain any unreasonable difference as to rates, charges, service, facilities, or other respect, either as between localities or as between classes of service." Given that CFC's request is unnecessary, the Commission should reject it.

5.1.3.3. Postage – FERC Account 903.100

SCE bases its $15.309 million forecast in FERC account 903.100[734] on 2015 recorded adjusted expenses of $20.486 million. SCE adjusted this base cost to remove $4.839 million in savings achieved through operational excellence initiatives and $338,000 in savings from program changes.[735] TURN inappropriately recommends reducing SCE's forecast by $1.168 million.[736] TURN bases its proposed reduction on its recommendation to add three million more electronic bills to SCE's forecast.[737] As discussed in Section 5.1.3.1 above, SCE's forecast of electronic bills was appropriately developed based on projected response rates to marketing campaigns and default initiatives and SCE appropriately included related savings in its forecast for this GRC cycle.[738] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for this FERC account, and the Commission should reject TURN's proposed reduction.

5.1.3.4. Uncollectable Expenses – FERC Account 904

SCE bases its proposed uncollectible forecast factor[739] of 0.216 percent on the most recent five-year average recorded expense, after removing the uncollectible expenses resulting from the Residential Disconnection OIR.[740] TURN recommends that the Commission reduce SCE's proposed uncollectible forecast factor to 0.211.[741] TURN agrees with SCE's forecasting method, but recommends using a five-

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[734] FERC Account 903.100 includes postal expenses for over 43 million billing statements and 7.1 million notices, reminders, and correspondence.
[735] Exhibit SCE-19, p. 33.
[736] Exhibit TURN-03, p. 21.
[737] Exhibit TURN-03, p. 21.
[738] Exhibit SCE-19, p. 34-35.
[739] FERC Account 904 includes costs for all revenue components of uncollectible customer accounts.
[740] Exhibit SCE-19, p. 35.
[741] Exhibit TURN-03, p. 24.

year average from 2012 to 2016, instead of 2011 to 2015, to reflect economic improvement "as California moves away from the Great Recession."[742] TURN offers no support for its theory about economic improvement or evidence that the lower uncollectible percentage will continue. Further, using 2016 data is not appropriate as it is preliminary and only adjusted at a very high level.[743] TURN should not be allowed to "cherry pick" and replace the highest data point with a much lower data point.[744] SCE's proposed five-year average is an appropriate forecasting method. Neither ORA nor any other intervenors propose any reductions to SCE's forecast uncollectible factor, and the Commission should reject TURN's proposed reduction.

5.1.4. SCE's Forecast for its Customer Contact Center Is Appropriate[745]

SCE's forecast for its Customer Contact Center (CCC) is appropriate and the Commission should reject TURN's request for reductions based on eliminating the adjustment for forecast customer growth. As discussed above, TURN's argument relies on inappropriate assumptions and is contrary to Commission precedent. SCE has demonstrated that customer growth directly impacts CCC's costs. TURN and Small Business Utility Advocates (SBUA) make additional recommendations for adjustments to CCC's forecast, which should also be rejected, for the reasons discussed below.

SCE bases its $46.289 million forecast in FERC account 903.800[746] on 2015 recorded adjusted expenses of $43.457 million. SCE adjusted this base cost to include $980,000 in customer growth, $579,000 in program changes (to support CCAs, time-of-use rates, and critical-peak-pricing programs), and $6.8 million for CS Re-Platform expenses. SCE also adjusted the base cost to remove $5.429 million in savings achieved through operational excellence initiatives.[747]

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[742] Exhibit TURN-03, pp. 23-24.
[743] Exhibit SCE-19, p. 36.
[744] Exhibit SCE-19, p. 36.
[745] ORA recommends denying SCE's requested $6.8 million in CS Re-Platform staff augmentation costs and allowing SCE to track those costs in a memorandum account and seek recovery through an advice letter. Exhibit ORA-12, p. 26. TURN supports this recommendation or, alternatively, requests a ten percent reduction in the forecast costs. Exhibit TURN-03, p. 23. SCE addresses this issue in its discussion of CS Re-Platform in Section 6.3 of this brief.
[746] FERC Account 903.800 includes expenses for SCE's Customer Contact Center, which handles 16.8 million inbound customer contacts annually, fulfills customer requests for service, addresses credit and billing inquiries, identifies usage patterns, supports sce.com, and discusses energy solutions and products with customers. The CCC also responds to emergency calls regarding outages, damaged equipment, and disconnection of service for non-payment 24 hours per day, seven days per week.
[747] Exhibit SCE-19, p. 37.

TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $980,000.[748] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for customer growth, and the Commission should reject TURN's proposed reduction. TURN bases its proposed reduction on the fact that the number of calls handled by live agents decreased from 2015 to 2016, alleging that customer growth therefore appears not to drive costs in this FERC account.[749] TURN is incorrect. TURN fails to demonstrate that customer growth will not directly impact CCC's costs. In fact, live agent calls, e-channel services, and costs related to interactive voice response (IVR) activities recorded to this FERC Account are driven by customer growth.[750] TURN offers no evidence that costs associated with these activities are not directly impacted by customer growth. TURN also fails to recognize that although live agent call volumes declined from 2015 to 2016, total call volumes increased by an average of 4.2 percent annually from 2012 to 2016.[751] Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $2.305 million in this specific FERC Account from its efforts to route calls to IVR.[752] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's customer growth forecast for FERC Account 903.800.

TURN also recommends reducing SCE's forecast labor costs by three percent, which would reduce SCE's forecast by $755,000.[753] TURN primarily relies on a noted 14 percent reduction in calls handled by customer service representatives from 2015 to 2016 and an 11 percent increase in IVR use to support this proposed reduction.[754] TURN's limited, selective analysis, however, fails to consider other costs in this FERC Account. Although total calls handled by customer service representatives have declined, the calls they are handling are significantly more complex, increasing average handle time (and associated costs) by 3.5 percent from 2015 to 2016.[755] TURN also fails to recognize that although

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[748] Exhibit TURN-03, pp. 22-23.
[749] Exhibit TURN-03, pp. 10, 22.
[750] Exhibit SCE-19, p. 39.
[751] Exhibit SCE-19, p. 39.
[752] Exhibit SCE-19, p. 39.
[753] Exhibit TURN-03, pp. 22-23.
[754] Exhibit TURN-03, p. 22.
[755] Exhibit SCE-19, pp. 40-41.

live agent call volumes declined from 2015 to 2016, total call volumes increased by an average of 4.2 percent annually from 2012 to 2016.[756] SCE expects the volume and complexity of customer contacts to continue to increase with additional CCAs forming and default time-of-use and critical-peak-pricing programs implementing in the test year.[757] Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $2.305 million in this specific FERC Account from its efforts to route calls to IVR.[758] For these reasons, the Commission should reject TURN's unsupported proposed reduction and approve SCE's forecast for FERC Account 903.800.

Although SBUA submitted certain recommendations concerning CCC activities[759] and SCE submitted rebuttal testimony addressing SBUA's recommendations,[760] SCE and SBUA entered a stipulation resolving the issues between them during evidentiary hearings.[761]

5.1.5. SCE's Forecast for its Business Customer Division is Appropriate

SCE's forecast for its Business Customer Division (BCD) is appropriate and the Commission should reject TURN's request for reductions based on eliminating the adjustment for forecast customer growth. As discussed above, TURN's argument relies on inappropriate assumptions and is contrary to Commission precedent. SCE has demonstrated that customer growth directly impacts BCD's costs. ORA and SBUA make additional recommendations for adjustments to BCD's forecast, which should also be rejected, for the reasons discussed below.

SCE bases its $18.520 million forecast in FERC account 908.600[762] on 2015 recorded adjusted expenses of $20.840 million. SCE adjusted this base cost to include $204,000 in customer growth and $945,000 in program changes. SCE also adjusted the base cost to remove $3.2 million in savings achieved through operational excellence initiatives and $270,000 in CS Re-Platform benefits.[763]

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[756] Exhibit SCE-19, p. 41.
[757] Exhibit SCE-19, p. 41.
[758] Exhibit SCE-19, p. 41.
[759] Exhibit SBUA-Michael Brown, pp. 33, 39-40.
[760] Exhibit SCE-19, pp. 41-43.
[761] Exhibit SCE-SBUA-1; Exhibit SCE-SBUA-2.
[762] FERC Account 903.800 includes expenses for SCE's Business Customer Division, including account management services, technical services, and energy education center groups. BCD engages, educates, and assists non-residential customers.
[763] Exhibit SCE-19, p. 44.

TURN inappropriately recommends eliminating SCE's proposed customer growth adjustment of $204,000.[764] Neither ORA nor any other intervenors propose any reductions to SCE's forecast for customer growth, and the Commission should reject TURN's proposed reduction. TURN offers no evidence to support its recommendation or demonstrate that costs associated with these activities are not directly impacted by customer growth. Further, TURN fails to acknowledge SCE's continuing productivity improvements and operational excellence efforts, which offset cost drivers including customer growth. SCE forecasts saving $3.2 million in this specific FERC Account from its operational excellence efforts.[765] For these reasons, in addition to the Commission precedent approving customer growth adjustments as a reasonable method of forecasting Customer Service costs, the Commission should reject TURN's proposed reduction and approve SCE's customer growth forecast for FERC Account 908.600.

ORA recommends reducing SCE's forecast for its "Dear Neighbor" program by $87,815. ORA recommends basing the forecast on 2016 recorded costs and assumes that volumes and costs will remain steady from 2016 to 2018.[766] SCE acknowledges that the volume and recorded costs were lower than forecast in 2016, but this was due to program restructuring and does not reflect the anticipated volume or costs going forward. In fact, SCE expects to meet or exceed its 2017 forecast of 75,000 mailers.[767] SCE's Dear Neighbor program is important to alert customers that may be affected by SCE maintenance activity, including outages, traffic, noise, and lane closures.[768] SCE has demonstrated the reasonableness of its request, no other intervenor opposed SCE's request, and the Commission should reject ORA's recommended reduction.

Although SBUA submitted certain recommendations concerning BCD activities[769] and SCE submitted rebuttal testimony addressing SBUA's recommendations,[770] SCE and SBUA entered a stipulation resolving the issues between then during evidentiary hearings.[771]

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[764] Exhibit TURN-03, p. 24.
[765] Exhibit SCE-19, p. 46.
[766] Exhibit ORA-12, p. 31.
[767] Exhibit SCE-19, p. 45.
[768] Exhibit SCE-19, p. 45.
[769] Exhibit SBUA-02, Brown, pp. 31-35.
[770] Exhibit SCE-19, pp. 47-49.
[771] Exhibit SCE-SBUA-01; Exhibit SCE-SBUA-02.

5.1.6. SCE's Forecast for its Customer Programs and Services is Appropriate

SCE's forecast for its Customer Programs and Services (CP&S) is appropriate and the Commission should reject proposed modifications made by TURN, National Diversity Coalition (NDC), and SBUA, for the reasons discussed below. SCE bases its $24.442 million forecast in FERC account 905.900[772] on 2015 recorded adjusted expenses of $24.483 million. SCE adjusted this base cost to include $4.44 million in program changes and remove $4.151 million in savings achieved through operational excellence initiatives and $330,000 in CS Re-Platform benefits.[773]

TURN recommends reducing SCE's new product opportunities forecast by 50 percent, because the group supports non-tariffed products and services, which cannot be funded by ratepayers.[774] TURN's recommendation, however, is based on a misunderstanding of how the new product opportunities group functions. The focus of the group is to develop and improve utility programs offered to ratepayers. Occasionally, the group may identify opportunities that could result in a non-tariffed product or service. That scenario, however, is incidental to the group's primary objective of identifying and improving utility offerings. Any incremental costs related to non-tariffed products or services will be appropriately charged to shareholders. Further, TURN's recommendation would limit the ability of SCE to identify and improve utility offerings to customers.[775] Neither ORA nor any other intervenor opposed SCE's forecast for new product opportunities. For these reasons, TURN's recommendation should be rejected.

NDC does not propose any changes to SCE's forecast, but makes several recommendations regarding SCE's marketing, education, and outreach (ME&O). NDC recommends that SCE (1) dedicate at least 40 percent of its major marketing campaign budgets for targeting minority groups, (2) increase its use of community-based organizations (CBOs), and (3) include an overview of its marketing planning process in testimony.[776] NDC's recommendations are unnecessary and not supported by record evidence. SCE's campaigns are designed and evaluated based on their effectiveness, including ethnic media buys. In fact, two of SCE's recent major campaigns were close to NDC's recommended spending level (39 percent and 38 percent, respectively), and demonstrate that SCE is committed to reaching its

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[772] FERC Account 905.900 includes expenses for SCE's consumer affairs, customer satisfaction, marketing communications and digital customer experience, product development, and program management groups.
[773] Exhibit SCE-19, p. 50.
[774] Exhibit TURN-03, p. 25.
[775] Exhibit SCE-19, p. 51.
[776] Exhibit NDC-01, pp. 21-24.

diverse customers.[777] SCE also uses CBOs as a valuable way to reach its customers currently and in the future.[778] NDC provides no evidence to suggest that SCE is not using CBOs at an appropriate level or even recommend what an appropriate level would be. Finally, SCE's testimony includes an overview of its marketing planning process, including campaign objectives, marketing approach, marketing channels, outreach to ethnic and at-risk communities, and measurement and results.[779] Neither ORA nor any other intervenor recommends changes to SCE's ME&O proposals. Because NDC's recommendations are unsupported and unnecessary, the Commission should reject them.

Although SBUA submitted certain recommendations concerning CP&S activities[780] and SCE submitted rebuttal testimony addressing SBUA's recommendations,[781] SCE and SBUA entered a stipulation resolving the issues between them during evidentiary hearings.[782]

5.1.7. SCE's Forecast for its Operating Unit Management and Support is Appropriate

SCE's forecast for its Operating Unit Management and Support (OUMS) is reasonable and unopposed by ORA or any other intervenors. SCE bases its $7.609 million forecast ($5.122 million in FERC Account 901[783] and $2.487 million in FERC Account 907.600[784]) on 2015 recorded adjusted expenses of $8.817 million ($2.487 million in FERC Account 901 and $6.330 million in FERC Account 907.600). SCE adjusted this base cost to remove $1.208 million in savings achieved by reducing consultants from FERC Account 901.[785] The Commission should approve SCE's reasonable and unopposed forecast.

5.2. Customer Service – Capital

For 2016 to 2020, SCE forecasts $174 million (nominal $) in capital expenditures for Customer Service meters, structures and improvements, and specialized equipment. This includes post-test-year

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[777] Exhibit SCE-19, p. 52.
[778] Exhibit SCE-19, pp. 52-53.
[779] Exhibit SCE-03R, pp. 184-189.
[780] Exhibit SBUA-02, Michael Brown, pp. 31-32; Exhibit SBUA-01A,Macaux/Rafii pp. 7, 10-15.
[781] Exhibit SCE-19, pp. 53-57.
[782] Exhibit SCE-SBUA-01; Exhibit SCE-SBUA-02.
[783] FERC Account 901 includes activities within the senior vice president's office, business planning, and CSOD.
[784] FERC Account 907.600 includes activities within the senior vice president's office, business planning, BCD, and CP&S.
[785] Exhibit SCE-03R, pp. 218-220.

capital expenditures of $40 million in 2019 and $45 million in 2020.[786] Other than one adjustment to SCE's meter replacement forecast proposed by TURN, neither ORA nor any other intervenors proposed any adjustments to SCE's Customer Service capital forecast. For the reasons discussed below, the Commission should reject TURN's proposed adjustment and approve SCE's forecast.

TURN agrees with SCE's proposal to use a three-year average to forecast its meter replacements, but recommends averaging 2014 to 2016 instead of 2013 to 2015, which would reduce SCE's forecast by $15.81 million for the 2017-2021 period. TURN supports its recommendation by alleging that 2013 was not typical of current experience.[787] SCE, however, demonstrated that its forecast is reasonable and including 2013 in the three-year average more accurately reflects the future needs for replacing meters. SCE's three-year average forecast is appropriate because 2015 was the first year that SCE experienced a significant decline from Edison SmartConnect stabilization. SCE's forecast also allows for unforeseen failures from aging meters, firmware updates, 3G to 4G migration, cell relay replacement, and other enhanced capabilities.[788] Because SCE's forecast is appropriate, better reflects future needs, and will allow SCE to implement its future metering strategy, the Commission should reject TURN's proposal and approve SCE's forecast.

5.3. Customer Service – Other Operating Revenue

SCE's Other Operating Revenue (OOR) forecast is reasonable and unopposed by ORA or any other intervenors. For Test Year 2018, SCE forecasts $27.981 million in OOR.[789] This forecast is $4.274 million below 2015 recorded levels. The decrease is primarily due to proposed reductions in SCE's Late Payment Charge and Non-Residential Connection Charge and lower Opt-Out fee volumes. These fees reflect the reduced cost for SCE to perform many of these services.[790] The Commission should approve SCE's reasonable and unopposed OOR forecast.

The City of Lancaster, representing SCE's only CCA that is a party to this proceeding, supports SCE's proposed CCA service fees (a portion of the service fees contributing to SCE's OOR forecast).

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[786] Exhibit SCE-03R, pp. 10-11.
[787] Exhibit TURN-03, p. 26.
[788] Exhibit SCE-19, p. 59.
[789] SCE charges fees for services that are above the standard operational services provided by SCE, as SCE cannot fund these activities through general rates. The revenue received for these services is accounted for as Other Operating Revenue. SCE's proposal includes fees for certain services associated with service connections, returned checks, direct access, community choice aggregator programs, and other special services.
[790] Exhibit SCE-03RA, pp. 12-13.

SCE and the City of Lancaster filed a joint motion requesting approval of a settlement agreement recommending that the Commission promptly approve SCE's proposed CCA service fees, among other issues. The motion was not opposed by any parties, and the assigned administrative law judges issued a proposed decision on August 15, 2017, which, if adopted, would approve the settlement agreement.

5.4. Customer Service – Additional Issues

6. INFORMATION TECHNOLOGY

SCE's Information Technology Operating Unit (IT) is responsible for managing SCE's computing applications and technology infrastructure.[791] SCE presented a reasonable and well-substantiated IT O&M and capital expenditure request that would support the safe and reliable planning and operation of the electric system, defend against growing cybersecurity threats, maintain and improve customer and IT service desk functions, and deploy critical enabling software applications for core business processes.

Intervenors have proposed untenable reductions to SCE's O&M request. These recommendations include: (1) reducing SCE's Hardware/Software (HW/SW) license & maintenance agreements forecast,[792] (2) eliminating expenses related to Grid Modernization[793] and grid planning and analytics efforts,[794] and authorizing the tracking of these costs in a memorandum account, (3) eliminating expenses related to the HR Platform Modernization project,[795] and (4) removing and tracking IT O&M expenses related to the Customer Service (CS) Re-Platform project in a memorandum account.[796]

Intervenors have similarly proposed unreasonable reductions to SCE's capitalized software request. These include reductions to, and in some cases the complete elimination of, the following: (1) contingency costs for all capitalized software projects,[797] (2) cybersecurity expenditures needed to protect the grid, our administrative network, and customer information,[798] (3) projects related to the

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[791] Exhibits SCE-04, Vol. 1, p. 1; SCE-20, p. 1.
[792] Exhibits ORA-13, pp. 16-18; TURN-04, pp. 63-65.
[793] Exhibits ORA-13, pp. 6-9; TURN-04, pp. 66.
[794] Exhibit ORA-13, pp. 12-13.
[795] *Id.* at pp. 13-14.
[796] *Id.* at pp. 11-12.
[797] Exhibits ORA-13, pp. 22-27; TURN-04, pp. 67-73.
[798] Exhibits ORA-13, p. 29; TURN-09, p. 11. ORA and TURN both recommend the Grid Modernization Cybersecurity program costs be tracked in a memorandum account. Additionally, TURN recommends all

improved planning and analysis of the grid,[799] and (4) the Vegetation Management, Comprehensive Situational Awareness Tool, and Enterprise Content Management applications.[800]

Collectively, these reductions would imperil our ability to maintain the basic operability of SCE's core computing environments. These recommendations would similarly put the grid, our administrative network, and customer information at risk to the growing volume and complexity of cyber-attacks. In addition, these proposed reductions would prevent SCE from implementing the tools necessary to improve the safe and reliable operation of the grid and the integration of distributed energy resources into the system. The record demonstrates that SCE has provided extensive justification for the need and reasonableness of the IT programs and costs requested in this GRC. The proposed reductions by intervenors do not adequately refute these justifications, and more importantly, they do not adequately consider the negative impacts that these collective reductions would create. Thus, SCE respectfully requests that the Commission fund SCE's IT funding request in its entirety.

6.1. O&M and Hardware

6.1.1. Hardware/Software Licenses & Maintenance

SCE provided a transparent, itemized forecast for Hardware/Software Licenses that are critical to SCE's operations. The Hardware & Software Licenses & Maintenance account includes the costs required to maintain SCE's IT hardware and software assets through license and maintenance agreements. Hardware maintenance includes: (1) hardware break/fix for IT equipment (e.g., servers and storage) that are no longer supported by the manufacturer under warranty; and (2) agreements to support destruction of storage media consistent with cyber security standards for protection of personal, customer, NERC CIP, and other confidential data. Software licenses and maintenance costs include software support agreements that give SCE access to break/fix support, service patches, minor and major upgrades, etc. for a large variety of software products managed by IT. This support is vital to securely operate and maintain the reliability and performance of our business applications. The updates from

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other cybersecurity programs be tracked in a memorandum account. As a secondary proposal, TURN agrees with ORA's position related to cybersecurity.

[799] Exhibits ORA-13, pp. 35-37; SEIA/Vote Solar, pp. 6, 9.

[800] Exhibits ORA-13, pp. 31, 33-34, 37-40.

vendors typically address cybersecurity updates or vulnerabilities, defects, performance improvements, and support for operating system upgrades.[801]

ORA's and TURN's recommendation to adopt the 2016 recorded expense for this account would decrease SCE's itemized forecast of $70.73 million to $62.77 million, a reduction of nearly $8 million.[802] SCE provided an itemized list of each license and maintenance agreement that make up the forecast,[803] but neither ORA nor TURN challenged any individual license or agreement. Instead, ORA simply states that SCE's request is "excessive" and that SCE failed to provide adequate support for its forecast.[804] SCE has introduced detailed evidence supporting its requests, but ORA has not met its burden of going forward. SCE has met its burden of proof.[805]

ORA and TURN also ignore SCE's proposed OpX savings of over $13 million for this account.[806] When these savings are included, the effective amount SCE is requesting for Hardware & Software License & Maintenance is $57.63 million, which is $5 million *lower than ORA's and TURN's recommendation*.[807] Similarly, when TURN argues that SCE failed to exclude from the itemized list those licenses that it expects to retire,[808] TURN is disregarding SCE's reductions and removal of licenses from its forecast as part of the OpX efforts.[809] When viewed in this light, SCE's forecast for this account is reasonable.

If ORA's and TURN's recommended $8 million reduction were to be added on top of SCE's proposed $13 million in OpX reductions, it would cripple SCE's ability to support critical business services. Such a large reduction would result in SCE foregoing vendor support, which would terminate SCE's access to critical vendor security updates and could potentially put protected information or other confidential data at risk of cyber-attacks.[810] ORA's and TURN's proposed reduction also disregards the

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[801] Exhibit SCE-20, Vol. 1, pp. 7-8.
[802] Exhibits SCE-20, Vol. 1, p. 8; ORA-13, p. 16; TURN-04, p. 65.
[803] WP SCE-04, Vol. 1C, p. 46-51, attached to Exhibit SCE-20, Vol. 1 as Appendix D, pp. D18 – D25.
[804] Exhibit ORA-13, p. 17.
[805] *Re Pacific Bell*, D.87-12-067 at p. 22, 27 CPUC2d 1. *See also Universal Studios Inc. v. Southern California Edison Co*., D.04-04-074, pp. 31-32, 2004 Cal. PUC LEXIS 173; *Re Golden State Water Co*., D.07-11-037, 2007 Cal. PUC LEXIS 648.
[806] Exhibit SCE-20, Vol. 1, pp. 11-12.
[807] *Id.* at p. 12 and Table II-3.
[808] Exhibit TURN-04, pp. 64-65.
[809] Exhibit SCE-20, Vol. 1, p. 11.
[810] *Id.* at p. 10.

growth and vendor escalation in hardware and software licenses and maintenance agreements from 2016 to 2018, which leads to higher costs in some areas.[811]

SCE presented a transparent, itemized list of licenses and maintenance agreements required to operate the business efficiently and safely. No party challenged any individual license or agreement, and no party challenged the $13 million in OpX reductions that SCE proposed for this account.
The Commission should adopt SCE's forecast of $70.73 million and associated OpX savings of $13.10 million.

6.1.2. Business Integration & Delivery (BID)

SCE has demonstrated that it needs incremental O&M funding for BID to support additional projects. SCE's forecast for BID is $44.643 million, which is based on 2015 recorded costs plus incremental O&M expenses for five project areas: (1) CS Re-Platform; (2) New Grid Planning & Analytics; (3) Grid Modernization; (4) HR Platform Modernization; and (5) Digital Experience SAS.[812] No party objects to SCE's base 2015 recorded-cost forecast or to the incremental O&M to support the Digital Experience SAS project. ORA recommends, however, that the Commission adopt memorandum accounts to track the capital-related O&M requests for (1) CS Re-Platform, (2) New Grid Planning and Analytics, and (3) Grid Modernization, instead of authorizing any incremental funding for these projects in this GRC.[813] In addition, ORA recommends zero incremental funding for the HR Platform Modernization project on the basis that SCE should already have adequate funding to complete this project.[814] For the reasons stated below, the Commission should adopt SCE's BID incremental forecast for these projects.

6.1.2.1. Customer Service Re-Platform

SCE addresses ORA's recommendation for the incremental funding for BID to support the CS Re-Platform Capitalized Software project in Section 6.3 below.

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[811] *Id.* at pp. 13-14.
[812] *Id.* at p. 16.
[813] Exhibit ORA-13, pp. 12-13.
[814] *Id.* at p. 14.

6.1.2.2. New Grid Planning and Analytics

SCE's incremental O&M request for New Grid Planning and Analytics will provide required support for the Grid Interconnection Processing Tool, Grid Analytics Application, Long Term Planning Tool, and Grid Connectivity Model. Due to accounting rules, this support work cannot be capitalized with these projects.[815] ORA asserts these incremental funds should be rejected since SCE developed its O&M expense forecasts during the pre-planning phases of these projects.[816] ORA seems to misinterpret the "pre-planning phase" nomenclature, but the pre-planning phase is part of the standard SCE IT project lifecycle for all capitalized software projects.[817] ORA also objects to these O&M funds because the capital projects this O&M will support are "dependent on the outcomes of several open proceedings."[818] SCE addresses the merits of each of these projects in Section 6.2.4.3. If the Commission adopts these projects, it is necessary for the Commission to also adopt these associated capital-related O&M expenses.

6.1.2.3. Grid Modernization

SCE's incremental O&M request for certain Grid Modernization projects will provide required support for the System Modeling Tool (SMT) and the DRP External Portal (DRPEP) projects.[819] Due to accounting rules, this support work cannot be capitalized with the projects.[820] ORA does not provide any specific analysis or justification against the reasonableness or forecasting methodology for these projects.[821] Therefore, to the extent the Commission approves the requested capital amounts for the System Modeling Tool (SMT) and the DRP External Portal (DRPEP) projects presented in SCE-02, Volume 10, the O&M related to these capital projects should also be approved.

6.1.2.4. HR Platform Modernization

SCE reduced its original forecast for the HR Platform Modernization project to $930,000 to implement only one module (the Learning Solution module) in this GRC period.[822] ORA objects to

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[815] Exhibit SCE-20, Vol. 1, p. 17.
[816] Exhibit ORA-13, pp. 12-13.
[817] Exhibit SCE-04, Vol. p. 38.
[818] Exhibit ORA-13, p. 13.
[819] Exhibit SCE-20, Vol. 1, p. 18.
[820] *Id.*
[821] Exhibit ORA-13, p. 13.
[822] Exhibits SCE-20, Vol. 1, pp. 20-21; SCE-04, Vol. 1A2, pp. 47-48 (errata showing the reduced forecast).

SCE's request for incremental O&M funding to implement this project because it believes that existing funding that is supporting the current SAP ERP ECM system "can be used to offset any new O&M SCE incurs" to implement the new project.[823] But ORA is mistaken in its assumption; SCE must use existing funding to pay for the ongoing SAP licensing costs until all functionality is transferred to newer systems.[824] That transition will happen after this GRC cycle.[825] Implementing this HR Platform Modernization project requires incremental funding because it will follow the software development lifecycle, just like a capitalized software project.[826]

ORA does not question SCE's need to implement this project and simply misunderstood the needed costs. Therefore, the Commission should adopt SCE's incremental forecast to implement the Learning Solution module, as SCE has proven that such costs are reasonable.

6.1.3. Grid Services

SCE has demonstrated that it needs incremental O&M funding for the Grid Services group to support Grid Modernization capital projects. The Grid Services group manages critical 24x7 operational functions to support the electric grid (electric and generation control systems, grid communication network, grid data center, grid and telecommunication operation centers, and grid security operations). SCE used last recorded year (2015) as the basis for its forecast and added incremental O&M to support four Grid Modernization capital projects:[827] The Grid Management System, Wide Area Network, Field Area Network, and Common Substation Platform.[828] If the Commission adopts these capital projects, it is necessary for the Commission to also adopt these associated capital-related O&M expenses.

ORA and TURN do not object to the base last year recorded forecast,[829] but they both object to the incremental O&M funding for Grid Modernization project support. ORA objects to all Grid Modernization and DER-related projects in SCE's GRC, including this O&M funding to support those

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[823] Exhibit ORA-13, p. 14.
[824] Exhibit SCE-20, Vol. 1, p. 19.
[825] *Id.*
[826] *Id.*
[827] Exhibits SCE-20, Vol. 1, p. 21; SCE-04, Vol. 1A, p. 60.
[828] These capital projects were requested in SCE-02, Volume 10 – Grid Modernization.
[829] Exhibits ORA-13, p. 7; TURN-04, p. 66.

projects.[830] ORA and TURN recommend that all Grid Modernization costs be tracked in a memorandum account.[831] SCE also addresses these arguments in Section 4.10 above.

ORA's argument that SCE did not provide sufficient details to support its incremental labor and non-labor expenses related to Grid Modernization projects[832] is erroneous. In response to data requests,[833] SCE provided granular detail for the O&M needed to support each Grid Modernization project, including year-by-year labor estimates, the number of FTE needed per year, the title and function for each FTE, and a breakdown of the non-labor forecast by year and by type of work performed.[834] SCE has met its burden of proof regarding the incremental O&M expenses needed to support the Grid Modernization projects.

In addition to recommending that these O&M incremental expenses be placed in a memorandum account, TURN also provides an alternate proposal, which would provide an additional $1.4 million to the Grid Services 920/921 activity to support TURN's recommendation to implement ADMS (Advanced Distribution Management System) and DERMS (Distributed Energy Resource Management System) instead of the full GMS (Grid Management System).[835] If the Commission adopts TURN's capital proposal, SCE agrees with TURN's recommendation to provide associated incremental O&M of $1.4 million to this activity for ADMS and DERMS.[836]

Similarly, in its Grid Modernization proposal, TURN adopts portions of SCE's Common Substation Platform (CSP) request.[837] Even though TURN recommends partial approval of the capital component of the CSP, TURN fails to likewise recommend partial approval of the O&M associated with the capital project. If the Commission were to adopt TURN's alternate recommendation for the CSP, it should likewise adopt the required capital-related O&M expense, which SCE calculates to be $196.984 million.[838]

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[830] Exhibit ORA-13, p. 7.
[831] Exhibits ORA-13, p. 9; TURN-04, p. 66.
[832] Exhibit ORA-13, p. 8.
[833] *See* SCE response to ORA-SCE-041-DAO, Q.01 – Supplemental, located in Exhibit SCE-20, Vol. 1, Appendix B., pp. B-6 – B-14.
[834] Exhibit SCE-20, Vol. 1, pp. 23-24.
[835] Exhibit TURN-06, p. 51.
[836] Exhibit SCE-20, Vol. 1, p. 24.
[837] Exhibit TURN-06, p. 86.
[838] Exhibit SCE-20, Vol. 1, p. 25 and Table II-7.

If the Commission adopts the Grid Modernization capital projects, the Commission should adopt SCE's forecast for incremental Grid Services O&M to support those projects.

6.2. Capitalized Software

6.2.1. Contingency Amounts in Capitalized Software Forecasts

SCE included contingency amounts in its capitalized software forecasts that are reasonable and necessary. Consistent with IT industry best practices, SCE incorporates amounts for contingency in many of its capitalized software project forecasts to account for uncertainties and variables that are unknown at the time SCE estimates the cost of a project.[839] The amount of contingency that SCE applied to projects in this GRC varies from 0% to 20%,[840] with the exception of the CS Re-Platform project, which included a 24% contingency.[841] ORA recommends that SCE receive only a 10% contingency for most software projects[842] and a 15% contingency for the CS Re-Platform project.[843] TURN recommends denying all contingency amounts in SCE's software forecasts.[844] As demonstrated in SCE's rebuttal testimony and through the testimony of expert witness Bruce Webster, ORA's and TURN's recommendations are flawed and are inconsistent with IT industry best practices.

While acknowledging that a certain amount of contingency may be needed for a project, ORA recommends that only a 10% contingency be included for most projects because SCE has not adequately supported its request for a 20% contingency.[845] But Mr. Webster, an expert with over 40 years of experience in software engineering and projects[846] and who has reviewed over 100 disputed or failed IT projects,[847] testified that SCE's practice of including contingency is consistent with industry best practices because "software projects are known for being high-risk ventures, with a significant risk of

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[839] *Id.* at p. 24A.
[840] *Id.* at p. 31, Table III-9.
[841] Exhibits SCE-04, Vol. 3, p. 29; SCE-20, Vol. 2, p. 3. The CS Re-Platform project forecast includes a total contingency of roughly 24%, which consists of a Project Complexities contingency plus a Delivery Contingency.
[842] ORA appears to have mistakenly assumed that all software projects had a 20% contingency amount. In fact, the software projects presented in this GRC have a range of contingency amounts. Exhibit SCE-20, Vol. 1, pp. 30-33.
[843] Exhibit ORA-13, pp. 27, 42.
[844] Exhibit TURN-04, p. 67.
[845] Exhibit ORA-13, p. 27.
[846] Exhibit SCE-20, Vol. 3, pp. 1-2.
[847] SCE, Webster, Tr. 8/897-898.

going far over the original budget and schedule, or failing altogether."[848] Mr. Webster believes that ORA's recommendation of a 10% contingency for most projects and 15% for the CS Re-Platform project is "unreasonable and inconsistent with the IT industry body of knowledge regarding IT project estimation and management."[849] Mr. Webster opined that SCE's inclusion of a 20% contingency for most projects is "modest" and "reflects significant confidence on the part of SCE at being able to bring these projects in within that contingency level,"[850] while the 24% contingency SCE included in the CS Re-Platform project "may be too low" because of the size and risks of that project.[851]

In justifying its claim that no contingency should be applied to SCE's software projects, TURN cites a book by Steve McConnell to argue that a project estimate "is just as likely to be off on the high side as it is on the low side."[852] But Mr. Webster points out that McConnell's book does not support this conclusion; McConnell's book instead demonstrates that "IT project schedules and costs in the real world are almost universally underestimated" and 70 out of 80 real-world software projects were "underestimated, and *not a single one* was overestimated."[853] In sum, Mr. Webster believes that TURN's recommendation that no contingency be included in software project estimates is "unrealistic and highly risky."[854]

In support of its recommendation that the Commission deny SCE's entire contingency request, TURN also argues that ratemaking principles allow for utilities to spend more than forecast with little risk and that ratepayers should not bear the risk of funding projects that don't materialize as expected.[855]

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[848] Exhibit SCE-20, Vol. 3, p. 15; SCE, Webster, Tr. 8/894 (testifying that going over budget "is a chronic issue in the software industry"); SCE, Webster, Tr. 8/896-897 ("[B]ecause of the invisibility and inherent complexity of software, it is not unusual to get partway through a project and discover difficult problems that will either force you to back up and rethink your fundamental architecture and design, or will require solutions that are going to take more time and effort in order to achieve completion.").

[849] Exhibit SCE-20, Vol. 3, p. 6.

[850] *Id.* at p. 16.

[851] Exhibit SCE-20, Vol. 3, pp. 17-18; *See also* Exhibit SCE-20, Vol. 2, pp. 3-4 (describing the particular complexities and risks of the CS Re-Platform project).

[852] Exhibit TURN-04, p. 70.

[853] Exhibit SCE-20, Vol. 3, p. 8.

[854] *Id.* at p. 7; SCE, Webster, Tr. 8/899-900 ("If you are looking at a situation where there has to be a delay in bringing the funds to bear, I think that has ultimately distorting influence on the project itself, in my opinion."); SCE, Webster, Tr. 8/900-901 (testifying that in a failed IT project that he analyzed, there were tight budget constraints that resulted in the company using "people who were less qualified. They delayed in hiring the right technical resources. And then as the project slipped, they actually started rolling people off the project to try to lower their burn rate.").

[855] Exhibit TURN-04, pp. 68-69.

Citing a December 2010 Commission decision involving PG&E, TURN suggests that SCE bears little risk if a project that included reduced or no contingency goes over forecast because the additional amount can be trued up in a subsequent GRC cycle.[856] But as Russ Worden explains, "[i]n the three-year cycle when the utility spends above authorized levels, it forgoes earning the authorized rate of return from the time the capital additions were made until the next test year. To the extent the assets cost more than what the utility was authorized to collect between test years, the utility would effectively be providing free service to customers from these assets between GRC test years."[857]

Mr. Worden also testified that the PG&E decision on which TURN relies (D.10-02-032, resolving PG&E's rate design window application) is inapposite because there, the Commission had authorized a memorandum account that would permit PG&E to accrue the capital revenue requirement beginning the day the new capital asset began service.[858] If TURN's proposal prevails, and SCE cannot recover any of its forecast contingencies, it would lose the revenue requirement associated with that legitimate business expense. That is not only unfair, but results in poor ratemaking policy, as the calculations from Mr. Worden's illustrative capital project shows.[859]

As Mr. Webster testified, when constrained by a tight budget, IT project managers often cut corners, putting the project at risk.[860] Thus, if the Commission were to adopt TURN's recommendation to eliminate all contingencies, there is a high likelihood that many (if not most) software projects will be hampered or go over forecast, and SCE will inequitably be on the hook for the overspent amounts (that otherwise would be covered by the industry-standard contingency) until the next GRC test year.

Finally, ORA and TURN attempt to draw a conclusion that SCE did not spend the full contingency it was authorized as support for their arguments that SCE does not need the contingency amounts it included in its project forecasts.[861] ORA's reasoning is flawed because its analysis inappropriately included projects that have not yet been completed. Until a project is completed, it

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[856] *Id.*
[857] Exhibit SCE-25, Vol. 3, pp. 3-4.
[858] *Id.* at p. 34.
[859] *Id.* at pp. 34-35.
[860] SCE, Webster, Tr. 8/900-901 (testifying that in a failed IT project that he analyzed, there were tight budget constraints that resulted in the company using "people who were less qualified. They delayed in hiring the right technical resources. And then as the project slipped, they actually started rolling people off the project to try to lower their burn rate.").
[861] Exhibits ORA-13, p. 23; TURN-04, pp. 71-73.

cannot be known to what degree the planned contingency will be used.[862] Each project is unique, and contingency must be evaluated for each individual project based on the particular risks and complexities of that project.[863] ORA also cherry-picked three projects from the 2015 GRC for its conclusion that "use of a contingency is almost unnecessary as the projects have come in under budget."[864] But SCE identified several projects adopted in the 2015 GRC that had expenditures far greater than the total cost estimate including contingency amounts.[865]

Mr. Webster's unequivocal opinions and the well-known IT industry sources that SCE discusses in its rebuttal testimony[866] demonstrate that SCE's contingency amounts are necessary to mitigate project risk, are consistent with industry best practices, and are reasonable. Moreover, there is precedent for contingencies being included in SCE's software project forecasts; the Commission adopted higher levels of contingency in previous GRCs than the 20% SCE requests for many projects in this GRC.[867] The Commission should adopt the contingency amounts that SCE has included in each of its capitalized software project forecasts.[868]

6.2.2. Cybersecurity and Compliance

SCE's Cybersecurity and Compliance organization ("C&C") works to safeguard and maintain the confidentiality, availability, integrity, and accountability of information technology systems and operations. The organization accomplishes this through security engineering, risk management, and ongoing industry and government outreach. In addition to these core functions, the C&C team also oversees regulatory compliance activities across IT and develops appropriate programs necessary to maintain compliance with evolving federal and state legislation involving cybersecurity.

SCE requests $308.5 million from 2016-2020 to fund seven critical cybersecurity and compliance projects, including: (1) Perimeter Defense, (2) Interior Defense, (3) Data Protection,

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[862] Exhibit SCE-20, Vol. 1, p. 28.
[863] Exhibit SCE-20, Vol. 3, p. 14.
[864] Exhibit ORA-13, pp. 23-24.
[865] Exhibit SCE-20, Vol. 1, p. 30.
[866] *Id.* at pp. 25A – 27.
[867] *Id.* at p. 27.
[868] ORA and TURN both made errors when calculating the amounts to reduce SCE's capitalized software forecast to account for their recommended contingency amounts. *See* Exhibit SCE-20, Vol. 1, pp. 30-33. Should the Commission decide to adopt a lower contingency amount than SCE requested for one or more projects, the Commission should review the worksheet attached to Exhibit SCE-20, Vol. 1 in Appendix C, pp. C-27 – C-31 to perform the correct calculations. *See* Exhibit SCE-20, Vol. 1, p. 33.

(4) SCADA Cybersecurity, (5) Common Cybersecurity Services for Generator Interconnection, (6) NERC CIP Compliance for IT, and (7): Grid Modernization Cybersecurity, which is discussed below in Section 6.2.3.[869]

6.2.2.1. SCE Does Not Object To ORA's Position that 2016 Recorded Costs Be Used For Capital Projects, Including SCE's Cybersecurity & Compliance Programs.

ORA proposes that the Commission use SCE's 2016 recorded capital expenditures in place of SCE's originally forecast 2016 capital expenditures.[870] SCE does not object to this. The only other reduction proposed by ORA is that the contingency amounts for these projects be reduced similarly with all other capital projects. SCE disagrees with ORA's position on contingency and addresses that argument above in Section 6.2.1.

6.2.2.2. SCE Opposes TURN's Recommendation That The Commission Remove All Capital Expenditures Related To Cyber Into a Memorandum Account.

TURN claims that it was unable to analyze whether SCE's request was reasonable, and asks that the Commission remove all costs from this GRC proceeding and move them to a memorandum account.[871] TURN had the information and opportunity it needed to properly assess SCE's request. SCE opposes TURN's position that these costs be placed in a memorandum account.

6.2.2.2.1. The Evidence Demonstrates That SCE Needs All Of Its Ongoing C&C Capital Projects.

As an initial matter, SCE met its burden of proof in establishing that it needs all the requested cyber-related capital projects in this GRC to protect the Company, the grid, and the public from cyber-attacks. First, regarding Perimeter Defense technology, this outer layer of defense is needed to prevent

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[869] SCE notes that its C&C O&M forecast of $18.133 million was not challenged.
[870] Exhibit ORA-13, pp. 2, 28-29.
[871] As a backup position, TURN asks that the Commission adopt ORA's position which is that all ongoing IT projects be adopted as requested by SCE using 2016 recorded costs as opposed to forecasted costs (as discussed above) and that Grid Modernization Cybersecurity be tracked in a memorandum account. SCE addresses ORA's position that all Grid Modernization Cybersecurity be tracked in a memorandum account below in section 6.2.3.

unauthorized intrusion from external threats into SCE systems.[872] Widely-used defenses such as firewalls are included in SCE's Perimeter Defense request, and SCE provided ample testimony about why such defenses are needed.[873]

Second, SCE needs the Interior Defense program to protect and secure SCE's internal systems from improper and unauthorized breaches and attacks.[874] SCE provided testimony regarding these interior threats and the steps SCE is taking to address these threats.[875]

Third, regarding the Data Protection program, this defense is necessary to protect customer information, employee information, and other SCE business information from authorized use, reproduction, or destruction.[876] A common example of such a threat is identity theft.[877] SCE presented evidence as to why it needs the Data Protection program and the anticipated costs associated with the program.[878]

Fourth, as established by SCE's testimony, the SCADA Cybersecurity program is needed to protect attacks on SCE's Supervisory Control and Data Acquisition ("SCADA") system, a feature of the grid.[879] A well-known example of a SCADA-related attack is the recent Black Energy attack that affected the Ukrainian power grid.[880]

Fifth, it is imperative that SCE continue and complete its Common Cybersecurity Services ("CCS") for Generator Interconnections project. The evidence demonstrates that completing this project is necessary to protect the grid.[881]

And finally, SCE has established that it needs funds to provide IT support for the ongoing, changing, and anticipated NERC Critical Infrastructure Protection ("CIP") requirements.[882] SCE must comply with FERC-ordered existing requirements and new and anticipated requirements.[883] In this GRC, SCE has established that it needs the requested funding to provide support for existing NERC

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[872] Exhibit SCE-04, Vol. 2, pp. 16-17, 19-20.
[873] *Id.*
[874] Exhibit SCE-04, Vol. 2, pp. 17, 21-23.
[875] Exhibit SCE-04, Vol. 2, pp. 17, 21-23
[876] *Id.* at pp. 17, 23-25.
[877] *Id.* at p. 17.
[878] *Id.* at pp. 17, 23-25.
[879] *Id.* at pp. 17, 25-27.
[880] *Id.* at p. 26.
[881] *Id.* at pp. 28-30.
[882] *Id.* at pp. 37-42.
[883] *Id.*

CIP-006, CIP-014, CIP-010-2, and CIP-007-6.[884] SCE has also established that it will need funding for emerging and anticipated NERC CIP requirements using a reasonable forecast methodology; historical costs.[885]

In sum, all of the above ongoing cyber-related capital projects must be funded so that SCE can continue to protect its facilities, the Company, the grid, and its customers' information from cyber-attacks.

6.2.2.2.2. A Memorandum Account Is Inappropriate For Cyber-related Projects.

The Commission should fund SCE's cyber-related requests in this GRC and not adopt a memorandum account as suggested by TURN.[886] The cyber-attacks and risks that SCE faces are happening now, constantly. SCE's core focus for the cyber team must be to protect the grid, its facilities, the Company, and its customers' information from cyber-attacks. Because of the vital importance of these activities, SCE must be able to undertake all measures requested and approved through the GRC process, without the uncertainty of whether cyber-related spending will later be approved through the memorandum-account process. The evidence demonstrates that the cyber-related risks and attacks are serious, evolving, real, hostile, destructive, and ever-increasing.[887] It is risky for SCE to be subject to memorandum account second-guessing when it comes to protecting against such cyber-attacks.

Moreover, TURN has failed to establish why the Commission should deviate from its precedent. Cybersecurity is not an area where SCE has repeatedly and substantially underspent its authorized revenue, and thus there is no reason why the Commission should consider a memorandum account now. Quite the opposite—the evidence before the Commission establishes that SCE needs all cyber-related costs now through the regular GRC process.

Finally, SCE notes that, consistent with Mr. Webster's testimony concerning SCE's cost-estimate contingency amounts, adding "constraints" and price concerns on IT projects may result in using "people who [are] less qualified" and delays in hiring the "right technical resources."[888] These types of financial issues and matters should not be the primary driver of cyber-related projects given the

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[884] *Id.* at pp. 37-41.
[885] *Id.* at pp. 38-39, 41-42.
[886] SCE acknowledges that a new information sharing program is appropriate and welcomes the opportunity to create such a program in a separate proceeding. But for this GRC, SCE has met its burden that it needs cyber-related funds now and asks that the Commission adopt its request.
[887] Exhibits SCE-20, Vol. 1, pp. 37-38; SCE-04, Vol. 1, pp. 2, 48-49.
[888] SCE, Webster, Tr. 8/900-901.

potential devastating results. The Commission should acknowledge the very real and increasing threats that these cybersecurity programs address by declining to establish a memorandum account. Subjecting this spending to memorandum account treatment could compromise valuable resources and efforts that protect the grid, our customers, and our company.

6.2.2.2.3. SCE Provided Appropriate Cost Justification and Information To TURN While Meeting Its Obligations To Protect Sensitive and Classified Information.

TURN claims that it was unable to evaluate the reasonableness of SCE's cyber-related revenue requests because SCE did not provide sufficient specificity in the information it provided in its testimony or in its responses to data requests.[889] SCE offered and provided additional sensitive information during in-person meetings with TURN. TURN nevertheless criticizes SCE's prohibition on TURN's representatives taking handwritten notes, and states it needed additional meetings in order to evaluate SCE's cyber-related requests.[890] Such criticisms should not influence the Commission's decision on this matter, for several reasons.

First, SCE has provided the Commission with ample evidence regarding its need for cyber-related funds. SCE provided thirty-eight pages of testimony supporting SCE's O&M and capital requests related to cybersecurity — and this does not include the testimony related to Grid Modernization Cybersecurity.[891] And though the number of words is not a litmus test for whether an appropriate showing has been made, the thirty-eight pages of testimony before the Commission is replete with facts related to ongoing measures and programs needed to fight cyber-crimes.[892] For example, regarding the Interior Defense program, SCE testified that it needs to take measures to secure SCE's internal systems from authorized users, devices, and software.[893] And in order to do so, SCE will be: (1) extending its Identify and Access Management System to newer generation technology, (2) enhancing and expanding SCE's data collection capabilities to mine and potentially connect disparate pieces of data to form a clearer picture and early warning, (3) implementing technology to allow SCE to analyze collected information for security threats in a more automated and effective manner, and (4) initiating automated

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[889] Exhibit TURN-09, pp. 2-4.
[890] *Id.*
[891] Exhibits SCE-04, Vol. 1, pp. 2, 48-56; SCE-04, Vol. 2, pp. 15-30, 37-42; SCE-20, Vol. 1, pp. 33-42.
[892] Exhibits SCE-04, Vol. 1, pp. 2, 48-56; SCE-04, Vol. 2, pp. 15-30, 37-42; SCE-20, Vol. 1, pp. 33-42.
[893] Exhibit SCE-04, Vol. 2, pp. 17, 21.

alerts when questionable activity is detected to enable SCE to prevent attacks.[894] To suggest that SCE did not provide sufficient information in testimony regarding its request is inconsistent with the record.

Second, with regard to TURN's claim that SCE did not provide sufficient information in response to data requests, SCE notes that it provided detailed work papers and cost estimation spreadsheets for each of its C&C projects. But the truth remains that in this area of its operations, SCE cannot provide endless, highly sensitive, confidential, and in some cases "classified" information in response to written data requests simply because TURN asked. As TURN itself admits in its testimony, SCE and the U.S. energy sector are remarkably successful in defending against cyber-attacks[895] and one such way of thwarting such attacks is to limit the amount of highly sensitive information disseminated, especially in written form via potentially vulnerable internet channels. For example, had SCE provided a list of the firewall software used by SCE in response to a data request, a cyber-attacker could use the information to refine its efforts to attack SCE and target any potential weaknesses in those applications. SCE offered and provided additional sensitive information to TURN through an in-person meeting.[896] TURN itself admits that it was given answers to discovery previously deemed "sensitive" and that with the additional information received, it had an "improved understanding of SCE's cybersecurity program."[897]

Finally, TURN's protests that it was only provided with one meeting and that it was not permitted to keep its notes are erroneous. First, on the issue of note-taking, this is a matter of form over substance. TURN admits SCE answered its questions during in-person meetings.[898] There is no evidence in the record that SCE failed to answer a single question during the confidential in-person meeting. And as explained earlier, SCE cannot permit unauthorized parties to obtain classified information or retain highly-sensitive information in unsecured formats, such as handwritten notes. Any notes taken by TURN could be used by cyber-attackers if inappropriately obtained or inadvertently disclosed. As for TURN's claim that additional confidential sessions would have permitted TURN to better analyze

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[894] *Id.* at p. 22.
[895] Exhibit TURN-09, pp. 7-8.
[896] SCE notes that ORA requested and had two in-person meetings with SCE versus TURN's one meeting.
[897] Exhibit TURN-09, pp. 3-4.
[898] *Id.* at p. 3. ("[h]igh level cybersecurity organization details were first obtained during the sensitive briefing;" "[k]nowledge about systems and network design, program design, internal customer requirements, and other issues required to start asking informed questions about staffing was first obtained during a sensitive, in-person briefing at SCE's office"; "[t]his meeting provided TURN with an improved understanding of SCE's cybersecurity program").

SCE's showing, any failure to have more than one session is due to the actions taken by TURN, not SCE. TURN itself admits that it did not begin reviewing cybersecurity issues until early 2017, and then it needed time to conduct discovery and find a suitable expert.[899] SCE offered to provide TURN with additional in-person meetings, and none were requested.[900] It is simply incorrect to suggest that SCE failed to meet its burden because more in-person sensitive meetings did not take place. TURN could have started reviewing cyber-related testimony in 2016 and requested earlier in-person meetings, and additional follow-up meetings as needed — just as ORA did.

6.2.2.2.4. SCE Welcomes The Opportunity to Streamline How Cybersecurity Information Is Shared Both With Intervenors and the Commission.

TURN makes several recommendations regarding changes to the GRC process to streamline how cyber-related information is shared. SCE agrees that a greater understanding and process regarding information sharing is needed.[901] SCE suggests that the Commission raise this issue in a separate proceeding so that all parties could collaborate and develop an appropriate process.[902] This GRC proceeding is simply not the appropriate venue to vet and explore these issues.[903] All potentially affected parties must be able to weigh in, including other IOUs, Commission staff, and possibly even the federal government.

6.2.3. Grid Modernization Cybersecurity

As discussed earlier, SCE must implement Grid Modernization to support the evolving distribution system. Cybersecurity measures must be integrated in Grid Modernization components to ensure that the grid can identify, and is resilient to cyber-attacks. ORA recommends removing all Grid Modernization Cybersecurity from this GRC and tracking them in a Grid Modernization memorandum account, which is ORA's recommendation for all Grid Modernization costs.[904] As indicated earlier, TURN asks that all C&C capital costs be removed from the GRC and tracked in a memorandum account, including Grid Modernization Cybersecurity costs.[905] As a second position, TURN agrees with

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[899] *Id.* at p. 4.
[900] Exhibit SCE-20, Vol. 1, p. 40.
[901] *Id.* at p. 41.
[902] Exhibit SCE-20, Vol. 1, p. 41.
[903] *Id.* at pp. 41-42.
[904] Exhibit ORA-13, p. 29
[905] Exhibit TURN-09, p. 11.

ORA's recommendation, which accepts all ongoing IT capital projects utilizing 2016 recorded costs as opposed to forecast costs (discussed above) but removing Grid Modernization Cybersecurity into a memorandum account.[906]

6.2.3.1. It Is Vital That SCE Implement The Grid Modernization Cybersecurity Project

SCE must be able to secure the grid communications, computing, control and infrastructure platforms that have known and existing vulnerabilities.[907] The Grid Modernization project permits SCE to adapt to emerging threats to our critical infrastructure and is the most efficient way to remove and fix existing grid vulnerabilities.[908] Additional information related to SCE's Grid Modernization efforts can be found above in the Grid Modernization section.

As stated in SCE's testimony, cybersecurity is integrated into various Grid Modernization systems that require interoperability.[909] For example, cybersecurity controls for substations must operate with the Wide-Area Network ("WAN"), and cybersecurity controls for distribution automation edge devices must operate with the Field Area Network ("FAN").[910] Grid Modernization introduces new modern communications and automation that require modern cybersecurity safety controls.[911] These safety controls must be designed directly into the Grid Modernization project to help ensure that the new signals, systems, and devices are resilient to attacks.[912] Grid Modernization Cybersecurity is needed to protect the overall system by detecting, isolating, fixing or removing, and restoring compromised systems and devices to their normal function as quickly and efficiently as possible.[913]

As stated in SCE's testimony, SCE is undertaking a "defense-in-depth" strategy for Grid Modernization Cybersecurity, consisting of the following categories:

(1) Secure Administration Environments;

(2) Device Access Controls;

(3) User Access Controls;

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[906] *Id.* SEIA/Vote Solar oppose SCE's Grid Modernization project but provide no testimony specific to cyber.
[907] Exhibit SCE-20, Vol. 1, p. 45.
[908] *Id.*
[909] *Id.* at 46.
[910] *Id.*
[911] *Id.*
[912] *Id.* at pp. 46-48.
[913] *Id.* at p. 48.

(4) Advanced Malware Protections;

(5) Vulnerability Management;

(6) Data Encryption Services; and

(7) System Monitoring Services.[914]

SCE provided testimony regarding the dangers and risks associated with each of these categories and the safety measures SCE will take to limit such risks.[915] No party has provided specific testimony challenging the merits of such work. Thus, SCE respectfully requests that Grid Modernization Cybersecurity be authorized in its entirety along with SCE's Grid Modernization project.

6.2.3.2. Even If Grid Modernization Is Removed From This GRC, Grid Modernization Cybersecurity Costs Are Necessary Now To Fix Existing Vulnerabilities.

Even if the Commission removes Grid Modernization from this GRC or disallows the Grid Modernization requests, a portion of SCE's Grid Modernization Cybersecurity request is needed now to address known vulnerabilities.[916] SCE asks that 40-50% of SCE's Grid Modernization Cybersecurity request of $99.4 million (total for 2016-2020) be authorized now in this GRC so that SCE can undertake critical steps to protect SCE's existing grid against known vulnerabilities. SCE notes, however, that such work will only be a "patch" or "band-aid," and that the entire program must be implemented at some point. SCE believes that it will be more cost-effective to implement the requested Grid Modernization Cybersecurity project now in its entirety, rather than implement a fragmented solution with temporary fixes that will have to be overhauled in the future and ultimately costing more.[917]

6.2.3.3. A Memorandum Account Is Inappropriate For Costs Related To Cybersecurity.

As discussed above in the Grid Modernization section, SCE asks that its entire project be approved now and that a memorandum account not be used. In addition to the reasons stated in the Grid Modernization section, SCE notes that a memorandum account is even less appropriate for Grid Modernization Cybersecurity. As discussed in detail in Section 6.2.2.2.2 above, memorandum accounts

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[914] *Id.* at pp. 48-51.
[915] *Id.*
[916] *Id.* at p. 43, fn. 113.
[917] *Id.*

for costs associated with cybersecurity are inappropriate and should not be used. SCE echoes the same points raised in Section 6.2.2.2.2 here in relation to Grid Modernization Cybersecurity.

6.2.4. Other Capitalized Software

ORA and SEIA/Vote Solar challenge specific capitalized software projects. For the reasons explained below, the Commission should adopt each of these projects as proposed by SCE.

6.2.4.1. Vegetation Management (VM) Project

The VM project will improve the processes and workflows associated with the maintenance and tracking of 1.5 million trees located near SCE's electrical equipment. It will replace the current paper-intensive process with a digitized, map-based system, and provide the data and tools to perform better analytics and work management.[918] ORA does not challenge the need for this project, but it nevertheless recommends no funding for it because the Commission previously authorized it in the 2015 GRC, SCE deferred implementing it, and customers "did not receive any benefits" from the project.[919] But customers did receive benefit from SCE's decision to delay the VM project because SCE executed a new vegetation management contracting strategy, revamped its business processes, and was able to reduce the forecast for this project by $2 million.[920]

Moreover, SCE is responsible for making decisions to allocate and spend capital based on the best information available at the time.[921] This may result in modifications to the capital plan proposed and approved through the GRC.[922] Information available after a GRC decision should be incorporated into company decisions related to capital spending.[923] These decisions may result in some projects not starting as originally anticipated and/or other projects spending amounts higher or lower than originally forecast.[924] SCE prudently implemented part of the VM project where it made sense to do so, and it delayed and re-scoped the rest of the project to the benefit of customers.[925] The Commission should approve this valuable project.

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[918] *Id.* at p. 52.
[919] Exhibit ORA-13, p. 31.
[920] Exhibit SCE-20, Vol. 1, p. 53.
[921] *Id.* at p. 1.
[922] *Id.*
[923] *Id.*
[924] *Id.*
[925] *Id.* at p. 54.

6.2.4.2. Comprehensive Situational Awareness for Transmission (CSAT)

The objective of the CSAT program is to allow Grid Control Operators to assess the status of the entire transmission system at a glance and provide quick access to detailed data and robust analytics to make more informed decisions during critical operational periods.[926] Like the VM project, ORA does not appear to question the value or need for this project. Instead, ORA contends that customers did not receive any benefit from the project because it was delayed and SCE has not justified the additional $6 million that it forecasts to complete the re-scoped project.[927] The delay in the CSAT project launch was a result of the extended deployment and stabilization of the Phasor project, which needed to precede a successful CSAT implementation.[928] SCE prudently modified its plans originally outlined in the 2015 GRC for the CSAT project (formerly Phasor Analytics) so as to avoid even more delay and putting the entire project investment at risk.[929] The Commission should approve SCE's forecast for the CSAT project, which remains critical to the effective operation of the grid.[930]

6.2.4.3. Grid Planning & Analytics Software

SCE requested a portfolio of grid planning and analytics software projects composed of the following projects: Grid Interconnection Processing Tool (GIPT), Grid Analytics Application (GAA), Long-Term Planning Tools (LTPT), and Grid Connectivity Model (GCM).[931] ORA recommends that the Commission remove SCE's forecast for these projects from this GRC and authorize a memorandum account to record SCE's spending on DER-related (distributed energy resources) projects.[932] ORA believes that due to the uncertainty surrounding several open DER-related proceedings, it is difficult to assess the reasonableness of SCE's IT Capitalized Software requests in this GRC.[933] ORA further states that if SCE implements the projects prematurely, the software might become obsolete or unable to be integrated with other systems at a later date.[934] Similarly, SEIA/Vote Solar opposes these grid

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[926] *Id.* at p. 55.
[927] Exhibit ORA-13, p. 33.
[928] Exhibit SCE-20, Vol. 1, p. 55.
[929] *Id.* at p. 56.
[930] *Id.*
[931] *Id.* at pp. 57-59.
[932] Exhibit ORA-13, p. 37.
[933] *Id.* at p. 36.
[934] *Id.* at pp. 36-37.

modernization-related projects, claiming they are premature, excessive, and fail to provide net benefits to customers.[935]

Neither ORA nor SEIA/Vote Solar provide testimony specifically challenging the merits of these four projects. Nor could they; each of the four projects will provide SCE with essential tools to manage the current grid and the grid of the future:

The GIPT is a suite of integrated workflow and project management software tools that will allow customers to more quickly and efficiently connect electrical generation and load to the grid, speeding up the interconnection project lifecycle, improving the customer experience, and providing SCE with more timely and accurate interconnection data.[936]

The GAA will provide SCE engineers, operators, and distribution grid designers with improved analytical, visualization, and decision-support capabilities required to plan and operate the grid of the future, providing SCE personnel with the capability to perform analytics on large data sources, including smart meter data, weather data, outage data, and electrical network field measurement data (e.g., Supervisory Control and Data Acquisition, or SCADA, data).[937]

The LTPT is a set of software tools that will facilitate integrated planning and forecasting over a five-to-ten-year horizon to identify optimal solutions to system planning challenges, and it will provide advanced circuit and substation modeling to support distributed energy resources (DER) integration, power flow and system planning analyses, calculation of load blocks at circuit and substation levels, and capacity planning analyses.[938]

The GCM is a software model of SCE's complete electrical grid, replacing existing disparate and disconnected models and serving as the single, centralized source of connectivity information for all assets—from bulk generation down to the end-consumer meters. To provide up-to-date information about the grid, this connectivity model will receive near real-time information about device settings through multiple operational systems, such as the Distribution Management System (DMS).[939]

The Commission should not, as ORA suggests, make SCE wait for open DRP proceedings to conclude before implementing these important projects. First, TURN made this same argument in

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[935] Exhibit SEIA/Vote Solar, pp. 6, 9.
[936] Exhibits SCE-20, Vol. 1, p. 57; SCE-04, Vol. 2, p. 144.
[937] Exhibit SCE-20, Vol. 1, p. 58; SCE-04, Vol. 2, pp. 150-151.
[938] Exhibits SCE-20, Vol. 1, p. 58; SCE-04, Vol. 2, p. 155.
[939] Exhibits SCE-20, Vol. 1, p. 59; SCE-04, Vol. 2, pp. 161-162.

PG&E's 2017 GRC. The Commission rejected it, finding that each program in PG&E's request should be evaluated on the merits.[940] Second, ORA was unable to articulate in response to data requests which Commission statements in DRP proceedings indicate the policy changes that would impact the scope or objectives of these four projects or how these projects' objectives were incongruent with possible policy changes under consideration by the Commission.[941] ORA's argument that implementing these projects is premature therefore appears superficial.

Finally, because DERs continue to proliferate throughout our electric system every day, SCE must implement these projects now to effectively interconnect, plan for, and operate with the volume and complexity of DERs that are currently and will be connected to the grid.[942] This is true regardless of the outcome of DRP proceedings or the Commission's decision on SCE's Grid Modernization program request.

For example, SCE would have pursued the GIPT project regardless of whether there were DRP proceedings,[943] because there is specific Commission guidance that encourages utilities to improve their interconnection processing systems in order to achieve Commission goals.[944] In addition, the current tool that GIPT will replace lacks the functionality to effectively incorporate increasingly complex tariffs and interconnection requests, and it cannot be integrated with other internal systems.[945] Similarly, the GAA is the investment that realizes ORA's own recommendations to better utilize smart meter data through additional modest investment;[946] it should be pursued regardless of whether the Commission adopts SCE's Grid Modernization program request. Likewise, the LTPT requirements are not dependent

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[940] A.15-09-001, Assigned Commissioner's Ruling and Scoping Memo in PG&E's 2017 GRC, p. 13 (September 1, 2015) ("The scope of this proceeding should include evaluation of all of PG&E's forecast distribution-related investments, even if they may be conceptually related to the DRP proceeding. Like all of its forecast investments, PG&E must meet its burden to demonstrate that these investments are reasonable in order to be authorized to move forward with those that are established to be necessary beginning in 2017."); *See also* Exhibit SCE-20, Vol. 1, pp. 60-61.

[941] Exhibit SCE-20, Vol. 1, pp. 61-62.

[942] *Id.* at 62.

[943] *Id.*

[944] *E.g.,* D.16-06-052: Alternate Decision Instituting Cost Certainty, Granting Joint Motions to Approve Proposed Revisions to Electric Tariff Rule 21, and Providing Smart Inverter Development a Pathway Forward for PG&E, SCE, and SDG&E.

[945] Exhibit SCE-20, Vol. 1, p. 63.

[946] *Id.* at 64. ORA recommended that SCE "ensure the existing AMI system is fully leveraged" and "create an environment that fosters the development of new benefits from the sunk cost of AMI." Exhibit ORA-09, pp. 41-42.

on any open Commission proceedings, and its new functionalities are needed now to address the current forecasting, analysis, and overall planning challenges SCE faces due to antiquated planning software and methodology.[947] Indeed, the recent Assigned Commissioner's Ruling (ACR) adopting DER Growth Scenarios in the DRP further supports SCE's request for the LTPT in that it requires local disaggregation of forecast data.[948] The LTPT will provide SCE with capability to use statistical methods to disaggregate more accurately the California Energy Commission's Integrated Energy Policy Report (IEPR) Forecast to meet the ACR's requirement.[949] Finally, the GCM project is needed now to replace the current network model, which is inadequate for the demands of a modern distribution grid.[950]

The Commission should authorize these projects in this GRC regardless of its decision on SCE's Grid Modernization program request or the pending DRP proceedings as these four software applications are needed to maintain business-as-usual operations.

6.2.4.4. Enterprise Content Management (ECM) Project

The ECM project brings important functionality to SCE employees that is not currently available. The ECM project focuses on improving SCE's capabilities to manage a diverse and complex set of business records. It is composed of eight solutions to improve the accuracy of records across SCE's operating units and improve classification of information for SCE to meet its information protection needs.[951] ORA recommends no funding for this project because: (1) many of the functions for this ECM project appear to be the same functions already implemented in the related Electronic Document Management/Records Management (eDMRM) project;[952] (2) SCE appears to be seeking funding for digital signature technology in both the ECM and eDMRM;[953] and (3) SCE has not offered any assurance that it will not "abandon" the ECM project as it did with the eDMRM project, for which SCE's customers received no benefit.[954]

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[947] Exhibit SCE-20, Vol. 1, p. 66.
[948] R. 14-08-013, Assigned Commissioner's Ruling On The Adoption Of Distributed Energy Resources Growth Scenarios, pp. 1-2 (Aug. 9, 2017).
[949] Exhibit SCE-04, Vol. 1, p. 158.
[950] Exhibit SCE-20, Vol. 1, at p. 67.
[951] Exhibits SCE-20, Vol. 1, p. 68; SCE-04, Vol. 2, pp. 192-193.
[952] Exhibit ORA-13, p. 39.
[953] *Id.*
[954] *Id.* at p. 40.

ORA's objections are misplaced: First, five of the eight functions for this ECM project are completely distinct from the eDMRM capabilities already implemented, and SCE can take advantage of advancements in technology that were unavailable at the time it planned the eDMRM project.[955] Second, the digital signature technology that SCE plans to implement as part of the ECM project is distinct from the pilot SCE conducted as part of eDMRM.[956] Third, SCE has not "abandoned" eDMRM, and customers have received meaningful benefits from the parts of eDMRM that SCE implemented. There are over 12 million records in eDMRM today, and eDMRM will continue to serve as the official repository for managing engineering drawings and public safety records.[957] Finally, the amount that SCE has spent implementing a reduced-scope eDMRM coupled with the forecast for this ECM project is slightly *less* than the amount adopted in the 2015 GRC for the original eDMRM project.[958] The ECM project is reasonable, and approval is warranted.

6.3. Information Technology - Customer Service Re-Platform

SCE's Customer Service (CS) Re-Platform project will implement a new customer relationship and billing system that will perform several critical customer-service-related functions, including customer billing, account management, customer care, credit and collections, and accounts receivable.[959] SCE forecasts capital expenditures of $208.7 million (nominal $) from 2017 to 2020 and Test Year 2018 O&M costs of $17.4 million (constant 2015 $) to implement CS Re-Platform.[960] In addition to replacing an obsolete customer service system from the 1980s and other operational and cost-saving benefits, SCE demonstrated that CS Re-Platform is essential to meet changing customer needs and replace existing systems that are outdated, obsolete, costly to maintain, and increasingly likely to fail.

ORA, TURN, and SBUA generally support CS Re-Platform, but recommend certain modifications. They base their recommendations for modifications on incorrect facts, assumptions, or analyses and fail to support their proposals with record evidence. Although SBUA submitted certain recommendations concerning CS Re-Platform[961] and SCE submitted rebuttal testimony addressing

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[955] Exhibit SCE-20, Vol. 1, pp. 69-73.
[956] *Id.* at p. 73.
[957] *Id.* at p. 74.
[958] *Id.*
[959] SCE-04, Vol. 3, p. 1.
[960] SCE-04, Vol. 3A2, p. 27.
[961] Exhibit SBUA-Michael Brown, pp. 24-30.

SBUA's recommendations,[962] SCE and SBUA entered into a stipulation resolving the issues between them during evidentiary hearings.[963] The Commission should approve SCE's reasonable and justified request for CS Re-Platform.

6.3.1. SCE's Proposed Contingency Level Is Reasonable and Appropriate

ORA recommends reducing SCE's proposed contingency amount from 24 percent to 15 percent.[964] ORA relies on an analysis of six SCE projects, one of which has not been completed, to allege that SCE has a pattern of overestimating project risks to receive additional funding.[965] ORA, however, recognizes that a contingency is necessary for a project of this scope, and asserts that its proposed contingency level of 15 percent is within the range of Commission-approved contingency levels between 15 percent and 30 percent.[966]

ORA's proposed contingency level is not appropriate for a project of this size and complexity or consistent with industry standards. Contingency levels should vary based on project risk, as determined by scope, complexity, duration, and cost. SCE reasonably proposes a 24 percent contingency, of which the majority is delivery contingency, intended to cover the cost risks inherent in any large, complex software project.[967] The remaining contingency is for project complexities and is intended to cover expected regulatory changes, integration with legacy platforms, and technology portfolio upgrades.[968] ORA failed to consider these risks in its analysis. These contingencies are essential to help ensure successful and timely completion of a project of this scale and complexity. Further, SCE's expert witness, with over 40 years of experience, testified that ORA's recommendation is "unreasonable and inconsistent with the IT industry body of knowledge" and stated that SCE's proposed 24 percent contingency level is appropriate and "may be too low" because of the size and risk of the project.[969]

ORA's recommendation inappropriately relies on six smaller projects that are not comparable in complexity or duration to CS Re-Platform. These projects were solely provided as examples of instances where the Commission approved contingencies in the range of 15 percent to 30 percent, not as projects

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[962] Exhibit SCE-20, Vol. 2, pp. 18-23.
[963] Exhibit SCE-SBUA-1; Exhibit SCE-SBUA-2.
[964] Exhibit ORA-13, pp. 41-42.
[965] *Id.* at p. 43.
[966] Exhibit ORA-13, pp. 43-44.
[967] Exhibit SCE-04, Vol. 3, p. 35.
[968] Exhibit SCE-04, Vol. 3, p. 34.
[969] Exhibit SCE-20, Vol. 3, pp. 6, 17-18.

that are comparable or analogous to CS Re-Platform. Five of them were reduced in scope and leveraged alternate solutions to complete the basic scope without using the full contingency funds. SCE expects to use the full contingency budget to complete the sixth project.[970] These projects do not support ORA's recommendation. Further, SCE provided examples of several large, complex, multi-year projects that used all of their contingency or exceeded it to address unexpected activities or scope.[971]

For all the reasons discussed above and in Section 6.2.1 of this brief, the Commission should reject ORA's recommendation and approve SCE's proposed 24 percent contingency for CS Re-Platform.

6.3.2. SCE's Proposed Schedule for CS Re-Platform Is Reasonable and Achievable

TURN recommends removing the CS Re-Platform project from this GRC because it contends that SCE will not complete the project in the 2018 GRC period.[972] TURN relies on SCE's proposed contingency to support its argument.[973] TURN fails to recognize, however, that the proposed contingency is intended to mitigate potential delays due to project risks and complexities. SCE carefully developed its schedule, which is reasonable, achievable, and consistent with other large utility customer system implementation plans. SCE also prepared a prudent contingency estimate so that it has funds available to add resources or bring in experts to address issues that may arise and complete the project on time.[974] Other than mentioning risks that SCE planned for and can address through its contingency, TURN offers no evidence that SCE cannot meet the proposed schedule and complete CS Re-Platform within this GRC period. Neither ORA nor any other party recommended removing CS Re-Platform from this GRC, and the Commission should reject TURN's unsubstantiated proposal.

6.3.3. A Memorandum Account Is Not an Appropriate Cost-Recovery Method for CS Re-Platform O&M Costs

ORA and TURN recommend removing one-time O&M expenses and propose that SCE record them in a memorandum account and seek recovery through an advice letter process after CS Re-

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970 Exhibit SCE-20, Vol. 2, pp. 4-5.
971 *Id.* at pp. 6-7.
972 Exhibit TURN-04, pp. 74, 76.
973 *Id.* at pp. 74-76.
974 Exhibit SCE-20, Vol. 2, p. 8.

Platform is complete.[975] If the Commission rejects this recommendation, TURN proposes in the alternative that the Commission reduce SCE's forecast for staff augmentation in the Customer Contact Center by ten percent.[976] ORA bases its recommendation on alleged uncertainty about whether SCE will complete the hiring, training, and employment of supplemental staff within this GRC cycle and claims that the number of supplemental staff SCE proposes to add is unprecedented and uncertain.[977]

6.3.3.1. SCE's One-Time O&M Expenses are Reasonable and Necessary

As stated above, SCE thoughtfully developed the CS Re-Platform timeline and expects it to implement within this GRC cycle. SCE also carefully developed the estimates for resources necessary to support IT and Customer Service project implementation and supplemental transition staff, including billing services, credit and payment services, and the Customer Contact Center. ORA's analysis is flawed because it relies on historical staffing levels that do not reflect the support necessary for a project as unprecedented in its complexity and potential for business impact as CS Re-Platform.[978] Given that CS Re-Platform will replace the obsolete customer service system and perform essential customer-service-related functions, including billing, account management, and credit and collections for SCE's five million customers, it is reasonable to require high levels of supplemental support during implementation and stabilization.[979] Supplemental staff is necessary to manage increased workload, as new processes are learned, and during the transition while both the old and new systems must be used.[980] Supplemental staff is a standard best practice to maintain quality customer care and manage challenges, such as those faced recently by other utilities and municipalities, when implementing systems similar to CS Re-Platform.[981]

IT costs (FERC Account 920/921) include third-party labor to support project implementation activities such as system integrator, software vendor, managed service provider, testers, and trainers. These activities are unique to a project with the size and scope of CS Re-Platform and additional resources are therefore necessary to support the program.[982] Developing data conversion methods and

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[975] Exhibit ORA-12, p. 18; Exhibit ORA-13, p. 45; Exhibit TURN-03, pp. 10-11.
[976] Exhibit TURN-03, p. 11.
[977] Exhibit ORA-12, p. 18.
[978] Exhibit SCE-20, Vol. 2, p. 11.
[979] *Id.* at pp. 11-12.
[980] *Id.* at p. 14.
[981] *Id.* at p. 13.
[982] *Id.* at p. 10.

data cleansing activities are significant tasks for a project like CS Re-Platform, and SCE provided evidence supporting the need for supplemental resources to help with this transition.[983] SCE followed generally acceptable accounting principles in forecasting one-time project implementation activity costs as capital or expense.[984] The expense costs for 2018 to 2020 are included in this GRC and are critical to supporting the project implementation.

Billing services costs (FERC Account 903.500), credit and payment services costs (FERC Account 903.200), and Customer Contact Center costs (FERC Account 903.800) include supplemental staff to fulfill two essential roles: (1) provide pre-implementation backfill coverage so that existing SCE staff can train on the new system; and (2) support the anticipated increase in average handle time, exception volumes, processing volumes, and call volumes once the new system goes live.[985] An unprecedented number of business sub-processes will be changing as part of CS Re-Platform, including nearly 100 in billing services alone, for critical activities like overseeing the energy usage and billing process to provide accurate and timely billing for all customers.[986] Changing business sub-processes in credit and payment will impact critical activities like credit policy, customer verification, fraud prevention, customer risk assessment, collection activities, and minimizing arrearages and uncollectible expense.[987] Changes to 64 sub-processes in the Customer Contact Center will impact critical activities like responding to customer requests and inquiries, responding to reports of power outages, providing information about customer programs and services, and responding to 911 calls.[988] Well-trained supplemental staff is needed to facilitate a successful implementation and mitigate potential problems that could cause billing delays, credit and payment delays, delays in customer response times, and customer dissatisfaction during the transition.[989]

SCE carefully developed its forecasts for staff augmentation and TURN's assertion that the Customer Contact Center forecast should be reduced by ten percent relies on incorrect assumptions. TURN bases its recommendation on a decrease in calls to the Customer Contact Center from 2015 to

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[983] *Id.* at p. 11.
[984] Exhibit SCE-04, Vol. 3, pp. 28, 35-36.
[985] Exhibit SCE-20, Vol. 2, pp. 12-14.
[986] *Id.* at p. 12.
[987] *Id.* at p. 14.
[988] *Id.* at p. 15.
[989] *Id.* at p. 12.

2016.[990] SCE acknowledges this decline and incorporated that reduction into its forecast call volume.[991] Because SCE already incorporated this reduction into its forecast, the further reduction requested by TURN is unnecessary.

Neither ORA nor TURN provided sufficient evidence to prove that SCE's forecasts for one-time O&M expenses related to CS Re-Platform are unreasonable. SCE demonstrated that the forecasts are reasonable, necessary, and consistent with best practices, and should be approved as proposed. TURN's alternative request that SCE's staff augmentation for the Customer Contact Center be reduced by ten percent is similarly based on incorrect assumptions and should be rejected.

6.3.3.2. If One-Time O&M Expenses Are Not Approved, the Commission Should Authorize a Balancing Account

If the Commission elects not to approve SCE's one-time CS Re-Platform O&M expenses in this GRC, then SCE recommends that the Commission authorize a balancing account (instead of the memorandum account recommended by ORA and TURN) with (1) recovery capped at $52.3 million, (2) year-end transfers to the Base Revenue Requirement Balancing Account (BURBA) for cost recovery, and (3) annual review of recorded costs in the Energy Resource Recovery Account (ERRA) review proceeding. This proposal will give parties the opportunity to review recorded costs on a timely basis and allow SCE to recover costs annually, rather than waiting until the Commission approves an advice letter filed after CS Re-Platform is completed.[992]

6.3.3.3. If the Commission Approves a Memorandum Account, Corresponding CS Re-Platform Benefits Should be Removed from SCE's Forecast

If the Commission adopts ORA's and TURN's recommendation to track one-time CS Re-Platform O&M costs in a memorandum account, the contemporaneously occurring benefits projected for CS Re-Platform in this 2018 GRC period should also be removed from the forecast. This will treat the incremental benefits the same way as the incremental costs. SCE forecasts $1.75 million in Customer Service O&M benefits[993] related to CS Re-Platform process improvements and $3.63 million in IT

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[990] Exhibit TURN-03, pp. 10-11.
[991] Exhibit SCE-20, Vol. 2, p. 16.
[992] *Id.* at p. 17.
[993] FERC Accounts 586.400, 586.100, 903.500, 903.200, 903.800, 908.600, and 905.900.

O&M benefits[994] in the 2018 GRC.[995] Removing these benefits is necessary to equitably account for SCE's delayed cost recovery under ORA's and TURN's proposal.

6.4. Additional Issues

6.4.1. SCE's Use of Managed Services Providers (MSPs)

SCE carefully considered and performed extensive analysis before deciding to transition to a new IT operating model involving the use of MSPs to provide day-to-day IT operations.[996] SBUA criticized SCE's decision, arguing that outsourcing these IT functions has had several harmful effects and that the Commission should require SCE to hire SCE employees or local businesses to provide IT service desk support before approving SCE's request for this account.[997] SBUA and SCE entered into a stipulation resolving the issues between them during evidentiary hearings.[998] SCE also explained in rebuttal testimony that SBUA's criticisms were unfounded.[999] No other party challenged SCE's use of MSPs, and there is no evidence before the Commission that SCE's use of MSPs has produced any harmful effects. The Commission should therefore approve SCE's request for this account.

7. GENERATION

7.1. Generation – Nuclear Generation (Palo Verde)

No parties commented or proposed reductions to SCE's forecasts for Palo Verde O&M expenses and capital expenditures, except for ORA's global recommendation to adopt SCE's 2016 recorded versus 2016 forecast of capital expenditures. SCE agreed with this recommendation, and the Commission should approve SCE's Palo Verde forecasts with that one adjustment.[1000]

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994 FERC Accounts 920 and 921.
995 Exhibit SCE-20, Vol. 2, p. 18.
996 Exhibits SCE-04, Vol. 1, pp. 5-8; SCE-20, p. 5.
997 Exhibit SBUA, Michael Brown, pp. 35-37.
998 Exhibits SCE-SBUA-1; SCE-SBUA-2.
999 Exhibit SCE-20, pp. 6-7.
1000 *See* Exhibit SCE-21, Table II-6 and Table II-7, pp. 13-14.

7.2. Generation – Energy Procurement

7.3. Generation – Hydro Generation

No parties commented or proposed reductions to SCE's forecasts for Hydro O&M expenses and capital expenditures, except for ORA's global recommendation to adopt SCE's 2016 recorded versus 2016 forecast of capital expenditures. SCE agreed with this recommendation, and the Commission should approve SCE's Hydro forecasts with that one adjustment.[1001]

7.4. Generation – Catalina

SCE provides electric service to approximately 4000 permanent residents and 1 million tourists via a closed electric system via six diesel generators at SCE's Pebbly Beach Generating Station (PBGS) in Avalon on Santa Catalina Island.[1002] As a threshold matter, it is important for the Commission to know that providing electric service on Catalina Island presents unique challenges, which understandably increases SCE's cost to provide electric service. Diesel fuel, for example, comes from the mainland and must be transported via tanker trucks on barges.[1003] Because Catalina Island is an isolated system and the Catalina PBGS is the sole, centralized source of power, longer design and execution time is required due to the difficulty of working with energized wiring and equipment.[1004] Also, the control systems for PBGS, which date back to the 1960s, are generally obsolete and beyond their useful life.[1005] PBGS must be modernized, as changes in technology, regulation, and environmental issues have changed the way electricity is generated, monitored, and delivered.

SCE forecasts the following costs to provide electric service on Catalina Island:

- 2018 O&M at $4.374 million.[1006]
- 2016 & 2017 Capital for the PBGS Automation Project at $3.4 million and $3.249 million, respectively.[1007]

[1001] *See* Exhibit SCE-21, Table II-6 and Table II-7, pp. 13-14.
[1002] Exhibit SCE-05, Vol. 5, Pt. 2, p. 1.
[1003] *Id.*
[1004] *Id*. at p. 12.
[1005] *Id.* at p. 9.
[1006] *See* Table I-1 and Table II-3 in Exhibit SCE-05, Vol. 5, Pt. 2, pp. 2, 6.
[1007] *See* Table I-2 in Exhibit SCE-05, Vol. 5, Pt. 2, p. 2.

- 2016-2018 Capital for all other Projects under $3 million at $7.1 million,[1008] or alternatively, 2016 recorded at $0.007 million and 2017-2018 forecast at $2.207 million and $213,000 respectively.[1009]

SCE discusses each of the forecasts below.

7.4.1. 2018 O&M – Account 549.140

SCE's 2018 O&M forecast is $4.374 million.[1010] No party takes issue with SCE's 2018 O&M forecast, which should be adopted by the CPUC.

7.4.2. 2016 & 2017 Capital for PBGS Automation Project

SCE's PBGS Automation Project will automate the monitoring and control of the multiple systems comprising Catalina's generation resources, including the six diesel generators, Sodium Sulfur (NaS) battery, microturbines, Selective Catalyst Reduction Urea system, Continuous Emission Monitoring System, and auxiliary systems including 2.4kV and 12kV power distribution, and diesel fuel delivery and storage.[1011] As indicated earlier, Catalina Island generation is running on equipment technology installed in the 1960s,[1012] and the Automation Project is needed so that SCE can remain in compliance with environmental regulations and mitigate the risk of a major outage resulting from the failure of obsolescent equipment.[1013] As an example of the obsolescence, the alarm annunciator cabinet that sits in the control room today runs on an operating system two generations older than Windows 95 and requires the use of floppy disks.[1014] Also, the hard drive of the alarm system failed last year, and the PBGS was running without critical alarm monitoring due to lack of replacement parts until the alarms were cutover to the new DCS system.[1015] Another example is that the Operators monitor the system frequency by comparing an atomic radio controlled clock to a digital clock powered by the Catalina electric system.[1016]

The PBGS Automation Project's benefits and goals are summarized as follows:

[1008] *See* Table I-2 in Exhibit SCE-05, Vol. 5, Pt. 2, p. 2.
[1009] Exhibit SCE-21, p. 9-12; Exhibit SCE-29, p. 128.
[1010] *See* Table I-1 and Table II-3 in Exhibit SCE-05, Vol. 5, Pt. 2, pp. 2, 6.
[1011] Exhibit SCE-21, pp. 2-3; Exhibit SCE-05, Vol. 5, Pt. 2, p. 7.
[1012] *Id*. at p. 5.
[1013] *Id*. at p. 4.
[1014] *Id*. at p. 5, footnote 11.
[1015] *Id*.
[1016] *Id. See* also p. A-2 of Exhibit SCE-21 for an image.

- Reduce complexity for grid operators to minimize potential for error.
- Reduce frequency and duration of unplanned outages through predictive maintenance enabled by real-time equipment monitoring.
- Improve efficiency of diesel emissions.
- Eliminate obsolete technology, reducing the probability of lengthy unplanned outages should parts fail.
- Provide control system platform that meets SCE's standards and has the flexibility to accommodate future integration with new technology.[1017]

SCE's 2016 and 2017 capital forecasts for the PBGS Automation Project are $3.4 million and $3.249 million, respectively.[1018] ORA states that it does not oppose the PBGS Automation Project or SCE's 2017 forecast.[1019] However, for 2016, ORA proposes that the 2016 actual capital expenditure of $3.386 million be used in place of SCE's 2016 forecast of $3.4 million, which results in a downward adjustment of $0.014 million.[1020] SCE agrees with ORA's proposal to use 2016 recorded cost for the automation project instead of SCE's 2016 forecast.

TURN proposes $0 for 2016 and 2017, and moreover, that the Commission disallow approximately $12 million that SCE has spent on the automation project.[1021] In support of its position, TURN cites SCE's project delays, revised project scope, the lack of need of the project, and too few customers to support the work.[1022] TURN proposes that the only additional expense associated with the project that should be recoverable is the cost of re-doing 70 year old drawings,[1023] which cost $1.409 million and $655,114 in 2015 and 2016, respectively, and is forecast to cost $899,709 in 2017.[1024]

[1017] Exhibit SCE-05, Vol. 5, Pt. 2, pp. 7-8 (includes June 16, 2017 errata). Further, standardizing Catalina's control systems creates specific benefits relating to technician training, equipment, maintenance, ability to substitute parts and employees between sites, manufacturer support, and infrastructure foundation to enable future updates. Exhibit SCE-21, p. 7.

[1018] *See* Table I-2 in Exhibit SCE-05, Vol. 5, Pt. 2, p. 2.

[1019] Exhibit ORA-14, p. 34.

[1020] Exhibit ORA-14, pp. 33-34.

[1021] Exhibit TURN-03, pp. 27-29, $17.21 million of SCE's request less the $5.127 million authorized through 2013.

[1022] TURN also criticizes SCE for ignoring an under-sea cable to provide electricity, a project which would be costly and would not eliminate the need for a centralized, automated system on Catalina. *See* Exhibit TURN-03, p. 28; Exhibit SCE-21, p. 8.

[1023] Exhibit TURN-03, p. 29.

[1024] Exhibit SCE-21, p. A-1.

TURN apparently believes that SCE has not been prudent in its actions on this project. However, the PBGS Automation Project's relatively long history reflects SCE's early and optimistic estimates of the Project's costs,[1025] the difficulty of serving an isolated system, the complexity of the Project, and the need to make course corrections when circumstances change. For example, TURN believes that work was "simply thrown out," citing to SCE's 2015 decision to replace the Allen Bradley controllers with Emmerson Ovation DCS.[1026] However, TURN is mistaken. As indicated in SCE's testimony, SCE estimates that 90% of the previously purchased equipment is being used, including the Allen Bradley controllers being used for parts of PBGS such as the NaS Battery, the Desalination Unit, the Microturbine and Diesel controllers, or being used as spare parts at other generating stations,[1027] thus demonstrating SCE's prudence in handling a change in the Project's scope. SCE also addresses[1028] TURN's mistaken belief that SCE did not explain the benefits of consistency between PBGS with other generating station,[1029] and that SCE failed to check its drawings.[1030] On a complex and large project like the Automation Project, it is important that SCE have the flexibility to change the Project's scope, rather than be stuck on a path that could lead to additional costs for an inferior product.

More importantly, TURN's desire to dismiss the residents of Catalina because they have been subsidized by mainland customers[1031] or have "lived without a SCADA system for decades"[1032] flies in the face of SCE's commitment to serve the customers on Catalina Island at the same standard as other customers. Yes, serving customers on Catalina Island is challenging and relatively more expensive. However, the CPUC should approve the PBGS Automation Project, which is expected to be in service in 2017, given that it is needed and part of SCE's steadfast commitment to provide safe, reliable, and affordable electric service to <u>all</u> customers of the utility, including those in areas where it is more difficult to serve.[1033]

[1025] Exhibit SCE-05, Vol. 5, Pt. 2, p. 8.
[1026] Exhibit TURN-03, pp. 27-28.
[1027] Exhibit SCE-21, p. 7.
[1028] Exhibit SCE-21, pp. 6-8.
[1029] Exhibit TURN-03, p. 28; Exhibit SCE-21, pp. 6-7.
[1030] Exhibit TURN-03, p. 27; Exhibit SCE-21, pp. 7-8.
[1031] Exhibit TURN-03, p. 28 ("Tens of millions of dollars have already been spent on this island, subsidized by mainland customers, with questionable economics.").
[1032] Exhibit TURN-03, p. 28.
[1033] Exhibit SCE-21, p. 4. SCE's commitment to serve its customers on Catalina Island and complete the PBGS Automation Project is demonstrated by SCE's decision to finish the project even though the CPUC approved

7.4.3. 2016-2018 Capital Project for all other Capital Projects Under $3 million

As indicated in SCE's direct testimony, SCE's 2016-2018 forecast for all other capital projects under $3 million is $7.1 million (nominal dollars).[1034] SCE's request is based on SCE's forecast of various capital projects, include facility resurface paving, fence and gate replacements, air compressor replacements, PBGS plant seawall improvement, etc.[1035] As indicated in SCE's direct testimony, for 2016-2018, SCE's forecast is $1.450 million, $3.2 million, and $2.459 million, respectively.[1036]

ORA proposes that (1) for 2016, SCE use the 2016 recorded of $.007 million (as opposed to SCE's 2016 forecast of $1.450 million), and (2) for 2017-2018, SCE use a five-year average (2012-2016) (nominal dollars), which results in $488,000 for each year.[1037]

SCE's response to ORA's proposal is as follows:

- SCE agrees to use its 2016 recorded cost of $.007 million.[1038]

SCE also agrees with ORA's general approach in using an average to forecast costs for 2017-2018, but with the following changes:[1039]

- All available year (i.e., six-year, or 2011-2016) should be used in the average (instead of a five-year average, as proposed by ORA) to accurately depict better the historical expenditure level presented in SCE's testimony. In addition, to more accurately reflect procurement costs and consistent with the CPUC's direction in D.04-07-022, the averaging should be done in constant dollars and not nominal dollars (as proposed by ORA).[1040]
- Remove from the average the recorded costs associated with the mandatory 2013-2014 unit overhauls for Units 8 and 14 (approximately $1 million each) so that the six-year average is based on costs associated with the miscellaneous capital projects. This is appropriate since

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only $5.1 million direct capital expenditures (as proposed by TURN) through 2013 in SCE's 2015 GRC. *See* D. 15-11-021, pp. 31-32.

[1034] From 2016-2020, SCE's forecast is $12.5 million. *See* Table I-2 in Exhibit SCE-05, Vol. 5, Pt. 2, p. 2.

[1035] Exhibit SCE-05, Vol. 5, Pt. 2, p. 16. As indicated in SCE's direct testimony, details of these projects were available in SCE's workpaper. Id. (citing to WP SCE-05, Vol. 5, P. 02, pp. 37-40).

[1036] *See* Figure II-4 (nominal dollars) in Exhibit SCE-05, Vol. 5, Pt. 2, p. 16.

[1037] Exhibit ORA-14, p. 34.

[1038] Exhibit SCE-21, p. 9.

[1039] Exhibit SCE-21, pp. 10-12.

[1040] Exhibit SCE-21, p. 10.

the unit overhauls are scheduled and based on accumulated run time and manufacturer suggested schedules;[1041] thus they are generally known and can be forecast.

- Similarly, include the forecast cost for the overhaul of Unit 15 of $2 million in the 2017 forecast.[1042]

With the changes proposed by SCE, SCE's 2017-2018 capital forecast is $2.207 million and $213,000, respectively, or $2.420 million total.[1043]

For the above reasons, the Commission should adopt SCE's 2016-2018 forecast of $7.1 million, which is based on SCE's forecast for specific projects, as set forth in SCE's direct testimony. Alternatively, if the Commission intends to adopt an average (which SCE also generally agrees), then the average should include all available recorded years (2011-2016), should be based on constant dollars (not nominal dollars), and should reflect the removal of the recorded costs for the mandatory 2013-2014 overhauls for Units 8 and 14, while including the 2017 forecast cost for the mandatory overhaul for Unit 15. With these changes, SCE's 2017-2018 forecast would be $2.207 million and $213,000, respectively.[1044]

7.5. Generation – Other

7.5.1. Mountainview

No parties commented or proposed reductions to SCE's forecasts for Mountainview O&M expenses and capital expenditures, except for ORA's global recommendation to adopt SCE's 2016 recorded versus 2016 forecast of capital expenditures. SCE agreed with this recommendation, and the Commission should approve SCE's Mountainview forecasts with that one adjustment.[1045]

7.5.2. Peakers

No parties commented or proposed reductions to SCE's forecasts for Peakers O&M expenses and capital expenditures, except for ORA's global recommendation to adopt SCE's 2016 recorded

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[1041] Exhibit SCE-21, pp. 10-11.
[1042] Exhibit SCE-21, pp. 11-12.
[1043] *See* Table 1-5, Exhibit SCE-21, p. 12; Exhibit SCE-29, p. 128.
[1044] *See* Table I-5 in Exhibit SCE-21, p. 12.
[1045] *See* Exhibit SCE-21, Table II-6 and Table II-7, pp. 13-14.

versus 2016 forecast of capital expenditures. SCE agreed with this recommendation, and the Commission should approve SCE's Peakers forecasts with that one adjustment.[1046]

7.5.3. Mohave Closure

No parties commented or proposed reductions to SCE's forecasts for Mohave Closure O&M expenses and capital expenditures, except for ORA's global recommendation to adopt SCE's 2016 recorded versus 2016 forecast of capital expenditures. SCE agreed with this recommendation, and the Commission should approve SCE's Mohave Closures forecasts with that one adjustment.[1047]

7.5.4. Solar Photovoltaic

For SCE's solar photovoltaic program, SCE's 2018 O&M forecast for Account 549 is $1.510 million[1048] and $2.332 million in Account 550.[1049] SCE's 2016-2018 capital forecast is $1,480 million.[1050] No party challenged SCE's O&M or capital forecast, which should be adopted by the Commission.

7.5.5. Fuel Cells

For SCE's fuel cell program, SCE's 2018 O&M forecast is $379,000.[1051] No party challenged SCE's O&M forecast, which should be adopted by the Commission.

7.6. Generation – Additional Issues

8. HUMAN RESOURCES

8.1. O&M

8.1.1. Human Resources Department

For the Test Year 2018, SCE forecasts $43.792 million of expenses for the Human Resources Operating Unit (HR Department) in FERC accounts 920, 921, 923 and 926. No parties contested the reasonableness of SCE's forecast for HR Department O&M expenses.

[1046] *See* Exhibit SCE-21, Table II-6 and Table II-7, pp. 13-14.
[1047] *See* Exhibit SCE-21, Table II-6 and Table II-7, pp. 13-14.
[1048] *See* Figure IV-3 in Exhibit SCE-05, Vol. 5, Pt. 1, p. 13.
[1049] *See* Figure IV-4 in Exhibit SCE-05, Vol. 5, Pt. 1, p. 16.
[1050] SCE's 2016-2018 capital forecast is $1.480 million. *See* Table V-7 in Exhibit SCE-05, Vol. 5, Pt. 1, p. 18.
[1051] *See* Figure VII-5 in Exhibit SCE-05, Vol. 5, Pt. 1, p. 22.

8.1.2. Executive Officers

For the Test Year 2018, SCE forecasts $19.611 million for SCE Executive Officer cash compensation (salaries and short-term incentives) and non-labor expenses in FERC accounts 920 and 921. While ORA did not oppose this forecast,[1052] TURN and NDC both recommended reductions by isolating the short-term incentives costs to SCE Executive Officers under SCE's Executive Incentive Compensation Plan (EIC). TURN calculated its $2.673 million reduction by (1) applying a five-year average of SCE's EIC costs at target levels, rather than actual recorded EIC costs, to reduce the test year labor forecast by $0.979 million and (2) deducting 40% of the average EIC costs to remove the percentage SCE allocates to the EIC's financial performance goal, further reducing the forecast by $1.694 million.[1053] NDC arrived at its $4.219 million reduction by applying the average of SCE's 2013-2015 EIC expenses and then applying a 62.5% EIC goal-related reduction.[1054]

SCE's forecast of Executive Officer labor costs, including short-term incentive costs, is based on the five-year average of actual recorded costs from 2011 to 2015.[1055] In applying varying methodologies, TURN and NDC do not contend that SCE's forecast provides the most reasonable projection of what Executive Officer labor costs will be in the Test Year 2018. Rather, TURN and NDC selected methodologies solely to impose their views on what amount SCE should pay in Executive Officer short-term incentive compensation. There is no dispute that the ultimate costs of short-term incentive compensation payouts have fluctuated significantly due to the relatively small number of employees in the executive officer population and the varying performance levels on a year to year basis.[1056] In selecting a five-year averaging methodology, SCE followed Commission guidance to provide the most reasonable estimate of labor costs in the Test Year 2018.[1057]

Neither TURN nor NDC acknowledge that the actual recorded incentive awards were included in the Total Compensation Study (TCS). The TCS concluded that SCE's overall workforce compensation was at market and its Executive Officers' total cash compensation levels, in particular, were 17.7% below market.[1058] Notwithstanding undisputed evidence that SCE's total compensation is at market,

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[1052] Exhibit ORA-15, p. 7, lines 8-9.
[1053] Exhibit TURN-01, pp. 16-17.
[1054] Exhibit NDC, pp. 15-19.
[1055] Exhibit SCE-06, Vol. 1, p. 37.
[1056] Exhibit SCE-06, Vol. 1, p. 36-37.
[1057] D.89-12-057, 34 CPUC2d 199.
[1058] *See* Exhibit SCE-06, Vol. 3, p. 4, Table 1.

TURN's and NDC's reductions further rely on challenges to the EIC goals based on the perceived absence of customer benefit from their achievement. The EIC goals work collectively to incentivize participants to achieve all of the goals and exceed related metrics; the achievement of the goals reward high-performing participants for their efforts at a market-competitive level.

TURN and other intervenors repeatedly attack SCE's Financial Performance goal in the form of a core earnings target. None dispute that core earnings is an objective and widely utilized metric to assess a company's overall health and success. TURN's own evidentiary submission acknowledges: "Annual profit levels and the cost of credit are important metrics when considering the financial health of a company."[1059] No party disputes that SCE's customers benefit when SCE is able to access capital market financing on reasonable terms. It is also undisputed that constraints on SCE's ability to secure capital on reasonable terms naturally translates into higher customer rates.

The goals should not be scrutinized individually, as they all work together to benefit customers and shareholders alike. The Financial Performance goal provides a defined measure of workforce productivity, reliability, safety, customer satisfaction and efficiency. Greater workforce productivity and operational efficiency translate into lower expenses. The Financial Performance goal works in tandem with other EIC goals to push its participants to keep SCE financially sound and fiscally responsible for both its shareholders and its customers. Moreover, the achievement of the Financial Performance goal does not guarantee above-target payouts. In the most recent EIC plan year (2016), EIC award payouts were *below* target, even though SCE exceeded its core earnings target, as SCE determined that other metrics tied to non-financial goals were not sufficiently met.[1060]

The fact that the specific Safety goal (measured by three metrics: (a) "Days Away, Restricted or Transferred" (DART) rate, (b) zero worker fatalities, and (c) zero serious injuries to the public resulting from system failures) accounts for 10% of the Executive Officer's potential EIC award under recent iterations (2015 and 2016) of the plan should not be viewed as somehow quantifying the solitary value that SCE places on safety in its overall operations. SCE's designated "Safety" goal within the EIC plan goals is just one of the many ways in which SCE seeks to foster strong safety behavior, culture, and ownership with its executives.[1061] Other EIC goals also support worker and public safety and

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[1059] Exhibit TURN-01-A (public attachments), p. 44.
[1060] Exhibit SCE-22, Appendix A, pp. A-1 to A-3 (SCE's response to Data Request NDC-SCE-004, Q.04.)
[1061] *See* also, Exhibit SCE-15, p. 6 (discussion of Executive Safety Engagement, Leader Safety Roles and Responsibilities and Safety Leadership Development programs.)

engagement, including cybersecurity and physical security improvements, emergency preparedness, mitigation and recovery efforts, customer satisfaction, reliability and pole loading milestones. For the 2017 EIC, there are Foundational Goals addressing the avoidance of (a) worker fatalities, (b) serious injuries to the public resulting from system failures, (c) significant non-compliance events and significant disruptions, and (d) data breaches or system failures that adversely impact critical infrastructure or result in a breach of customer data.[1062]

In the event the Foundational Goals are not met, the EIC payout may be partially reduced or zeroed out depending upon severity.[1063] This determination is made by the Compensation Committee of the Board of Directors comprised of independent directors.[1064] In other words, the Compensation Committee retains discretion to completely eliminate the EIC award in the event of a serious safety violation and/or non-compliance event.

8.2. Benefits and Other Compensation

8.2.1. Short-Term Incentive Program

For the Test Year 2018, SCE forecasts $132.905 million for the Short-term Incentive Compensation Program (STIP) expenses covering its represented and non-represented workforce (except for SCE executive officers). ORA and TURN took varying approaches to proposing reductions to SCE's STIP forecast.[1065]

TURN proposes $57.592 million for SCE's 2018 Test Year STIP, which represents a total forecast reduction of $76.256 million. TURN calculates its recommended STIP forecast by first reducing SCE's forecast STIP/Labor ratio to 12.11%, the ratio applied by the Commission in the 2015 GRC decision, and then applying a 40% reduction based on the weight accorded to the Financial Performance goal in the most recent STIP matrix, to arrive at a forecast of $57.592 million.[1066]

[1062] Exhibit SCE-15, p. 7.
[1063] *Id.*
[1064] *Id.*
[1065] Although Small Business Utility Advocates (SBUA) submitted certain recommendations concerning SCE's Short-term Incentive Program (*See* Exhibit SBUA-02, pp. 46-47) and SCE submitted rebuttal testimony addressing SBUA's recommendations (*See* Exhibit SCE-22, pp. 11-12), SBUA and SCE entered into stipulations resolving the issues between them during the evidentiary hearings (*See* Exhibits SCE-SBUA-1 and SCE-SBUA-2).
[1066] Exhibit TURN-01, pp. 10-12.

ORA proposes a 45% reduction of SCE's 2018 STIP forecast solely based on adjustments tied to the STIP goals, comprising a 40% reduction based on the weight accorded to the Financial Performance goal and a 5% reduction representing half of the weight accorded to the High Performance Organization goals in the most recent STIP matrix.[1067]

No parties challenge SCE's testimony concerning the benefits associated with variable pay programs. Variable pay has been and continues to be an integral component of SCE's market-competitive total compensation package for its workforce, and places a portion of employees' compensation (increasing as a percent of total compensation based on job classification) at risk. Notwithstanding the continuing challenges by the various parties to STIP and other variable pay programs and the disallowances ordered by the Commission, SCE continues to fund these programs at market-appropriate levels because shifting the pay mix away from variable pay and toward base pay impedes SCE's ability to manage and motivate its employees and makes SCE's labor costs less flexible.

Similarly, no parties contend that SCE's forecast of STIP costs provided a reasonable estimate of the actual costs of STIP for Test Year 2018. As with TURN and NDC's recommendations for short-term incentive costs for SCE Executive Officers, the parties' challenges to SCE's forecast of STIP costs constitute their efforts to impose their views on the amount of short-term incentives SCE should pay to its represented and non-represented workforce at all levels (except for Executive Officers). In selecting an itemized forecast methodology utilizing the STIP costs from the base year (2015 STIP plan year, paid out in 2016), SCE followed Commission guidance to provide the most reasonable estimate of STIP costs in the Test Year 2018.[1068]

TURN's reduced forecast relies on a number of incorrect premises. TURN inaccurately claims that STIP is limited to "non-represented employees" even though both represented and non-represented SCE employees are eligible for STIP.[1069] TURN also inaccurately implies that below-target STIP performance allows SCE to take authorized funding from customers and apply such funds for other purposes.[1070] In fact, SCE's STIP funding is subject to a one-way memorandum account (STIPMA),

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[1067] ORA's recommended STIP forecast is also based on a reduced labor forecast. Differences between ORA's and SCE's forecast labor expense are addressed in other sections of the Opening Brief.
[1068] D.89-12-057, 34 CPUC2d 199.
[1069] Exhibit TURN-01, p. 5.
[1070] Exhibit TURN-01, p. 5.

which returns any over-collection for this specific expense through the Base Revenue Requirement Balancing Account (BRRBA) to customers.[1071]

TURN also incorrectly states that SCE's Test Year forecast is based on the 2015 payout of STIP awards (for 2014 plan year performance) when the eligible workforce received STIP awards based on Company performance that was 42.6% above the target level.[1072] In fact, SCE's Test Year forecast is based on the 2016 payout of STIP awards (for 2015 plan year performance), representing 4.6% above-the-target STIP expense in relation to the forecast.[1073] TURN is correct in noting that the higher STIP payout (for 2014 plan year performance at 42.6% above target) was included in the TCS. Since the TCS concludes that SCE's total workforce compensation is at market, this further supports the reasonableness of SCE's Test Year 2018 STIP forecast.[1074]

TURN's criticism that SCE's STIP program is skewed in favor of higher-ranking employees ignores the realities of workplace practices; namely, that higher-level employees generally receive higher variable pay opportunities as they are more willing to accept that a higher percentage of their total compensation is subject to the inherent volatility associated with variable pay opportunities. Employees with lower levels of base pay are generally not as willing to place a significant portion of their income "at risk." SCE's STIP is designed to properly reflect this reality of workplace practices, and the market levels of SCE's workforce compensation at all levels remain supported by the unchallenged results of the TCS. Contradicting its own purported concern over the disproportionate nature of short term incentive program payouts, TURN seeks the same levels of reduced funding for all STIP participants, regardless of job category levels.

TURN also criticizes the incremental rise in SCE's STIP forecast due to current and future-year job classification changes. TURN never accounts for the actions SCE has taken and continues to take to manage and reduce workforce compensation expenses for the benefit of its customers. It is widely recognized that the costs of non-cash compensation (including medical, pension and other retirement

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[1071] *See* Exhibit SCE-09, Vol. 01, p. 56.

[1072] Exhibit TURN-01, p. 7.

[1073] *See* Exhibit SCE-06, Vol. 2A2 *HR-Benefits and Other Compensation (2nd Errata)*, and SCE-22, Appendix C, p. C-2 (SCE's Supplemental Response to Data Request TURN-SCE-006 Q.01.f.)

[1074] Exhibit SCE-22, p. 14-15 (Due to the timing of the TCS and the TCS' inclusion of all cash compensation paid in the most recent complete year, the TCS considered STIP payments made in 2015 for the 2014 plan year. However, SCE's STIP forecast for Test Year 2018 applies data for STIP payments made in 2016 for the 2015 plan year.)

benefits) have climbed swiftly. As discussed by SCE witness Mark Bennett, the 2018 TCS and other reviews of SCE's workforce compensation showed that, although SCE's total compensation for all employees was at market, the cash compensation was below market, and benefits were above market in a number of job categories.[1075] This has prompted SCE to manage these expenses by changing the mix of cash and non-cash compensation. SCE took the proactive step of ending pension plan participation for new hires starting December 31, 2017 and discontinuing its retiree healthcare plan for employees hired on or after that same date. These steps are projected to reduce the long term cost structure of both of these programs.[1076]

The increased STIP forecast accounts for certain employee classifications that required an increase in cash compensation to keep their total compensation in line with the market and counterbalance the loss of certain benefits.[1077] SCE maintains that any increase in STIP costs will be mitigated by the decreases in the costs of pensions and post-retirement benefits other than pensions (PBOP) in coming years.[1078] Those cost decreases are already reflected in SCE's pensions and PBOP forecasts in this GRC.[1079] Although SCE's 401k plan costs will see an attendant increase in costs due to these changes, SCE did not include those increased 401k plan costs in its forecast for this GRC.[1080] Accordingly, any increases in STIP in this GRC are expected to be more than offset by the savings tied to eliminating the pension plan and retiree healthcare plan for new hires, and eliminating the Executive Retirement Plan for newly hired or promoted executives, after December 30, 2017.[1081]

The other rationales TURN and ORA use to justify their proposed reductions to SCE's STIP forecast rely on the recurring arguments over who (shareholders or customers) benefits more directly from the achievement of certain STIP goals. TURN and ORA argue that the Financial Performance goal, in particular, benefits shareholders exclusively or primarily. In addition to the overall TCS results which show SCE's total compensation (including STIP) to be at market, this view also ignores the importance of SCE's financial health to customers, including the critical role that SCE's financial condition plays in securing financing on reasonable terms for critical infrastructure and other capital projects. Core

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[1075] SCE, Bennett, Tr. 7/855:1-28.
[1076] *See* Exhibit SCE-06, Vol. 02, Sections IX.B, IX.F, and IX.I.
[1077] SCE, Bennett, Tr. 7/855:21-28.
[1078] Exhibit SCE-22, pp. 15-16.
[1079] *See* Exhibit SCE-06, Vol. 2, pp. 55 (lines 4-6) and 91 (lines 15-19); *See also*, SCE, Bennett, Tr. 7/839:10-25.
[1080] *See* Exhibit SCE-06, Vol. 2, pp. 55 (lines 4-6) and SCE, Bennett, Tr. 7/860:6-22 and 861:22-862:10.
[1081] Exhibit SCE-22, p. 15-16 and SCE, Bennett, Tr. 7/846:1-22.

earnings reflect SCE's revenues versus expenses; as such, it is a clear indicator of the cost efficiency of its operations.[1082] Just as with EIC, the STIP Financial Performance goal promotes the workforce's focus on affordability, safety, customer service, and cost control.

SCE's STIP and other variable pay programs are structured to promote individual and collective employee behavior that benefits both customers and the Company. A more realistic approach in evaluating these programs is to recognize that the mix of goals is interrelated, and that better reliability, safety, customer service, cost control, and diversity all contribute to the financial performance of the Company. Correspondingly, the Company's successful financial performance helps reduce the borrowing costs of capital to fund infrastructure investment, customer service projects, and other expenditures that support safe and reliable service. TURN's own materials acknowledge that: "the utilities that satisfy their customers are also more likely to be those that also satisfy their shareholders."[1083]

SCE's variable pay programs (including STIP and long-term incentives) are all included in the 2018 TCS. The Commission has directed SCE to submit the TCS and has relied upon it in past GRCs to show how SCE's workforce compensation compares to the market. The TCS results show SCE's total compensation is 1.9% below market. SCE respectfully asks the Commission to adopt its Test Year STIP forecast in full.

8.2.2. Long-Term Incentives

For the Test Year 2018, SCE forecasts $13.726 million in Long-term Incentive (LTI) expenses for its executive workforce. The various parties (namely, ORA, TURN, and NDC)[1084] all seek complete disallowance of SCE's LTI expenses. They do so even though the TCS concludes that overall compensation (including LTI) is at market. LTI is part of the total compensation package (along with base pay, benefits, and short term incentives) for all SCE officer and non-officer (*i.e.*, director-level)

[1082] Exhibit SCE-22, p. 11-12.

[1083] Exhibit TURN-01-A, p. 46.

[1084] *See* Exhibits ORA-15, pp. 11-13, TURN-01, p. 21, and NDC-1, pp. 20-21, Although Small Business Utility Advocates (SBUA) submitted certain recommendations concerning SCE's Long Term Incentives (*See* Exhibit SBUA-02, pp. 44-45) and SCE submitted rebuttal testimony addressing SBUA's recommendations (*See* Exhibit SCE-22, pp. 21-22), SBUA and SCE entered into stipulations resolving the issues between them during the evidentiary hearings (*See* Exhibits SCE-SBUA-1 and SCE-SBUA-2).

executives. As in past total compensation studies, the TCS assigns executive officer positions to the Executive category, and non-officer executive positions to the Manager/Supervisor category.

ORA's recommendation relies on an incorrect interpretation of current and historical TCS results and a flawed analysis of executive headcount data. ORA cites TCS reports submitted in SCE's 2012, 2015, and 2018 GRCs and incorrectly applies the data to conclude that SCE executive base pay has nearly doubled in six years.[1085] ORA's conclusion is inaccurate because: (a) the "Executive" category includes only SCE executive officers when the entire executive population, including non-officer executives, is eligible to receive LTI awards and those non-officer executives fell under the Manager/Supervisor category (not the Executive category); and (b) the SCE Payroll Dollars in the TCS are not limited to base pay, but also include short-term incentive awards.[1086] In rebuttal, SCE provided the actual figures showing that SCE's executives overall (including executive officers and non-officer executives) received an average annual base pay increase of 1.77% from 2009 through 2016 and, of that executive population, an average of 54% of executives received no annual base pay increase in any given year over the same period.[1087]

ORA further asserts that SCE's LTI program does not result in better executive-level retention based upon an analysis of SCE executive headcount data. But that analysis relies on erroneous assumptions of job titles and condenses positions with "slightly different" job titles that "appeared to be" the same jobs and positions that were "apparently" promoted.[1088] ORA's analysis did not consider other factors, including lateral transfers and organizational changes, and does not reflect the true tenure of SCE employees in executive-level positions. In fact, the average tenure of SCE's current executive population is 18 years of service, and from 2009-2016 a total of 88 executives retired from SCE with an average tenure of 27 years of service.[1089]

Beyond ORA's flawed analyses, neither ORA, TURN nor NDC ever refutes or otherwise challenges SCE's testimony concerning the benefits to customers tied to LTI. SCE's use of LTI as part

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[1085] Exhibit ORA-15, p. 12.

[1086] Exhibit SCE-22, Appendix F, pp. F-2 (2018 GRC, Ex. SCE-06, Vol. 03, p. 4, fn. 2), F-4 (2012 GRC, Ex. SCE-06, Vol. 02, Appendix B, p. B-5, fn. 2), and F-6. (2015 GRC, Ex. SCE-06, Vol. 2, Part 2, p. 4, fn. 3.)

[1087] Exhibit SCE-22, Appendix G, pp. G-9 and G-10. (SCE Executive Average Annual Base Pay Increase 2009-2016.)

[1088] Exhibit ORA-15, pp. 11-12.

[1089] Exhibit SCE-22, Appendix D, (Current SCE Executive Population: Average Tenure.) and Appendix E (Executive Retirements 2009-2016: Average Length of Service.)

of an executive's total compensation package helps conserve cash resources, because there is no immediate cash payment to employees for an LTI award due to the multi-year vesting schedule applicable to each form of LTI.[1090] Moreover, LTI awards do not trigger increases in an executive's annual/fixed pension and benefits costs that are a function of base pay, and conserving cash via the LTI component helps avoid interest on short-term borrowing, which represents a cost of service.[1091] Rather than refuting these arguments, TURN maintains that SCE has previously made these arguments in other ways to support LTI recovery and further seeks to characterize SCE's LTI expenses as "elective."[1092] However, SCE maintains that dispensing with LTI for its executives is simply not an option in the competitive executive labor market because they are offered by comparable employers and critical to recruiting and retaining executives.[1093] Moreover, SCE has supplemented its showing by clearly delineating the benefits to customers arising from LTI.[1094] Additionally, the 2018 TCS results provide further evidence supporting the reasonableness of SCE's requested levels of executive compensation, including LTI.

8.2.3. Recognition Programs

SCE requests recovery for its cash and non-cash recognition programs, namely the Spot Bonus and Awards to Celebrate Excellence (ACE) programs. The Spot Bonus program is designed to motivate and reward employees who accept and perform additional responsibilities in an exceptional manner or accept responsibilities or assignments that require extraordinary time commitments shortly after the completion of those assignments or upon hitting major project milestones.[1095] The ACE program utilizes non-cash awards to recognize employees for promoting a safe working environment through actions and behaviors and for helping contribute to public safety. SCE's historical and forecast expenses for the Spot Bonuses and ACE awards are included in the labor and non-labor, respectively, expense forecasts of individual Operating Units.

[1090] Exhibit SCE-06, Vol. 2, p. 35-36.
[1091] *Id.*
[1092] Exhibit TURN-01, pp. 19-20.
[1093] Exhibit SCE-06, Vol. 2, pp. 34-35.
[1094] Exhibit SCE-06, Vol. 2, pp. 35-36.
[1095] Exhibit SCE-06, Vol. 2, p. 39.

ORA recommends that the Commission reject funding for SCE's Recognition Programs based on lack of transparency and insufficient justification for the expense.[1096] As compared to its showing in the 2015 GRC, SCE expanded its testimony to explain in detail the manner in which these modest recognition program costs are managed, recorded costs of the programs for the base year, and the basis for its calculation of the test year forecast.[1097] Given the manner in which program costs are managed, SCE's use of a budget-based approach to manage costs of the programs and to forecast future expenses is prudent and reasonable.

In SCE's 2015 GRC decision, the Commission rejected ORA's proposed disallowance of SCE's Recognition Programs and observed that:

> 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.[1098]

Other recent Commission decisions have also approved rate recovery of similar recognition programs offered by other utilities with short-term incentive programs.[1099]

SCE's Recognition Programs remain effective tools to motivate employees with rewards for individual achievements and for promoting a safe work environment. The Commission has acknowledged these programs provide benefits to SCE customers by furthering the provision of safe and reliable service. As such, SCE requests that the Commission adopt its Recognition Programs forecast.

8.2.4. Pension

For pension costs in FERC Account 926, SCE forecasts $97.474 million for pension costs in the Test Year 2018 and $161.726 million and $162.895 million, respectively, for the 2019 and 2020 attrition years.[1100] ORA is the only party who made recommendations concerning SCE's forecast of pension costs. ORA did not contest the reasonableness of SCE's test year 2018 forecast of pension costs and ORA supported the continuation of the two-way Pensions Cost Balancing Account. However, ORA recommended applying the 2018 Test Year forecast of $97.474 million for both attrition years.[1101] In its

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[1096] Exhibit ORA-15, p. 14.
[1097] Exhibit SCE-06, Vol. 02, p. 41.
[1098] D.15-11-021, p. 267.
[1099] *See* D.13-05-010, pp. 884-885; D.14-08-032, p. 525.
[1100] Exhibit SCE-06, Vol. 2, p. 45.
[1101] Exhibit ORA-21, p. 9-11.

rebuttal testimony, SCE accepted ORA's proposal for the adjustments to its 2019 and 2020 pension forecast in order to narrow the number that must be litigated to conclusion in this GRC.[1102]

8.2.5. Medical Programs

For the Test Year 2018, SCE forecasts medical program costs of $110.719 million. SCE's forecast is based on applying escalation rates (0% for 2016, 7% for 2017, and 7% for 2018) to the 2015 recorded/adjusted costs. ORA's Test Year 2018 forecast is $101.478 million, $9.241 million less than SCE's forecast. Although ORA did not challenge SCE's forecast methodology for medical program costs, ORA applies a medical escalation rate of 4.58% to reduce SCE's Test Year 2018 forecast and further recommends utilizing that escalation rate for its post-test year mechanism.[1103]

ORA chose three sources of healthcare cost statistics to challenge the reasonableness of SCE's proposed medical escalation rate. ORA then calculated the average of the three insurance premium rate increases cited in these three sources – 4.7%, 5.6%, and 3.45%, respectively – to arrive at a proposed medical escalation rate of 4.58%.[1104] However, all of these sources are based on general survey data concerning the *average* trends of varying employee populations and employers with different medical benefit designs, usage experience, and methodologies employed for collecting data. SCE disputes the use of such "mitigated" cost trend rates where each set of data reflects the net impact of employer actions to moderate health care costs, such as changing vendors, modifying plan design and increasing required employee contributions.

SCE's forecast 2017-2018 medical trend rate of 7% is a *non-mitigated* trend rate. As SCE's represented workforce is subject to multi-year collective bargaining agreements (CBAs), significant medical plan changes may not occur in each year covered by the CBAs. In contrast, many employers who participate in general surveys can make changes to their medical programs each year, typically by either passing more costs to employees or reducing benefit coverage. This has an overall effect of reducing their trend rates. In contrast to the general survey data used by ORA, SCE asked its medical plan carriers develop future cost projections based on SCE's current covered populations and plan designs. As a result, these estimates are more accurate than broad, generic surveys of employers in general, which represent average health care increases. SCE's health care carriers are most familiar with

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[1102] Exhibit SCE-22, p. 27.
[1103] Exhibit ORA-21, p. 11.
[1104] Exhibit ORA-15, pp. 18-20.

SCE's cost profiles, and consider age and health factors that are specific to SCE's enrolled population in preparing their cost trend projections.

After reviewing all of that data, SCE reasonably determined that a 7% annual trend rate for its specific enrolled population was appropriate. SCE's trend rate is further supported by the rate setting process for SCE's 2017 medical plans showing the actual trend at 6.7%.[1105] Notably, SCE's medical carriers projected generally *higher* trend rates (ranging from 8.6% - 11%) than the rate selected by SCE for its medical trend forecast.[1106]

SCE has reasonably determined escalation rates for its medical programs. SCE utilized escalation rates supplied by its plan providers. These escalation rates provide the best estimate of the underlying costs for SCE's covered population. In contrast, ORA's forecast relies on more general survey data, and should be rejected.[1107]

8.2.6. Executive Benefits Program

For the Test Year 2018, SCE forecasts Executive Benefits Program costs of $21.087 million. The Executive Benefits Program comprises the Executive Retirement Plan that supplements the SCE Retirement Plan and certain other benefits not included in the rate request. ORA recommends disallowing 50% of SCE's Test Year 2018 forecast for Executive Benefits based on Commission decisions in SCE's past three GRCs and because ratepayers should not bear the full cost of supplemental benefits "which serve to further enhance benefits to already highly-compensated employees."[1108]

ORA does not dispute that SCE's forecast for Test Year 2018 provides a reasonable estimate of the actual costs of the Executive Benefit Program. These supplemental benefits are key components of a total compensation package that is at market. SCE's aggregate compensation for the five job categories surveyed by the 2018 TCS is at market, and SCE's total compensation for executives is at market. Additionally, SCE is proactively implementing changes to the Executive Retirement Plan beginning in 2018 to reduce the plan's long-term cost structure.[1109] SCE expects material reductions in associated

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[1105] Exhibit SCE-22, Appendix I, (Letter from Actuary Re: SCE 2017 Medical Plans Renewal Rate, Dated May 17, 2017.)
[1106] Exhibit SCE-22, p. 30.
[1107] Additionally, ORA applies a lower labor expense forecast, which had a corresponding effect on its medical program forecast. Differences between ORA's and SCE's forecast labor expense are addressed in other sections of the Opening Brief.
[1108] Exhibit ORA-15, p. 21.
[1109] Exhibit SCE-06, Vol. 02, pp. 100-102.

costs will be realized in the period following the current GRC cycle. Accordingly, SCE requests that the Commission adopt its Test Year 2018 forecast for the Executive Benefits Program.

8.3. Total Compensation Study

SCE's compensation policy is to offer employees market-based total compensation consisting of base pay, short-term and long-term incentives, recognition awards, and benefits. The Commission previously directed SCE to "present a study in which independent experts have undertaken all analysis with regard to benchmarks, job matching, and the selection of comparable firms."[1110]

A total compensation study compares the utility's total compensation – salaries, short- and long-term incentives, and benefits – to the relevant market. Compensation studies therefore require information from other firms, which is gathered through surveys conducted by an independent expert. The Commission has recognized "that wage surveys, like other surveys have a certain amount of error"[1111] and has accepted a 5% error rate as reasonable:

> [T]his commission has found that a 5% error rate is reasonable for compensation surveys. By this standard, one cannot conclude that a firm's compensation differs from the market average to a statistically significant degree unless the difference is at least 5%.[1112]

The TCS results are the only evidence of SCE's employees' total compensation in this GRC and are uncontested. The results of the 2018 TCS are presented below:[1113]

Job Category	Base Pay	Total Cash Compensation*	Benefits	Paid Time Off	Long-term Incentive	Total Compensation
Physical/Technical	11.1%	16.5%	6.1%	106.6%	--	15.0%
Clerical	-4.5%	-5.0%	2.6%	1.4%	0.0%	-3.2%
Professional/Technical	-13.2%	-11.2%	1.7%	-10.3%	-100.0%	-9.6%
Manager/Supervisor	-9.4%	-6.3%	0.5%	10.4%	-94.6%	-7.6%
Executive	-10.3%	-17.7%	96.4%	7.6%	-21.5%	-8.3%
Overall**	**-5.0%**	**-2.5%**	**4.3%**	**25.8%**	**-6.1%**	**-1.9%**

*Total Cash Compensation equals base pay plus short-term incentives.
**Overall numbers are payroll-weighted.

[1110] *Re Southern California Edison Co.,* D.96-01-011, 64 CPUC2d 241, 1996 Cal. PUC LEXIS 23.
[1111] *Re Pacific Gas and Electric Co.,* D.92-12-057, §5.3.4, 47 CPUC2d 143, 173, 1992 Cal. PUC LEXIS 971. *See* also, §5.3.2 of that decision for further discussion of the sources of compensation survey error.
[1112] *Re Southern California Edison Co.,* D.96-04-050, 65 CPUC 2d 362, 438, 1996 Cal. PUC LEXIS 270.
[1113] Exhibit SCE-06, Vol. 3, p. 4.

9. OPERATIONAL SERVICES

9.1. Business Resiliency

SCE's Business Resiliency organization provides company-wide governance and program management for business continuity, disaster recovery, assessment and mitigation, and emergency planning and response programs. SCE forecasts $7.964 million for Business Resiliency's O&M expenses for Test Year 2018. ORA contests the addition of an analyst in Business Resiliency to support Emergency Management Operations (EMO) training and exercise activities and requests removal of the associated $74,000 expense.[1114] The additional analyst to support EMO training and exercises emerged as SCE expanded its emergency response program from 2013 to 2016.[1115] This expansion resulted in the addition of approximately 300 new members to Incident Support Teams (IST) and Incident Management Teams (IMT) for 24/7 coverage over multiple operational periods.[1116] The lone existing analyst could not support the expanded teams, and, consequently, an additional analyst is needed to handle the additional training and exercise activities.[1117] Given the need for this additional analyst in support of SCE's emergency response program, SCE respectfully requests that the Commission reject ORA's recommendation and adopt SCE's Business Resiliency O&M forecast for Test Year 2018.

SCE accepted ORA's recommendations to adjust Business Resiliency's capital forecast for 2016 to correspond with 2016 recorded capital expenditures of $4.019 million,[1118] in order to narrow the issues that must be litigated to conclusion in this case. No other recommendations were made for adjustments to Business Resiliency's O&M or Capital forecasts.[1119]

[1114] Exhibit ORA-16, p. 5.
[1115] Exhibit SCE-23, Vol. 1, p. 4.
[1116] *Id.*
[1117] *Id.* at p. 5.
[1118] Exhibit SCE-23, Vol. 1, p. 7 (Table I-5.)
[1119] Although Small Business Utility Advocates (SBUA) submitted certain recommendations concerning Business Resiliency's capital forecast (*See* Exhibit SBUA-02, pp. 21-24) and SCE submitted rebuttal testimony addressing SBUA's recommendations (*See* Exhibit SCE-23, Vol. 1, pp. 7-9), SBUA and SCE entered into stipulations resolving the issues between them during the evidentiary hearings (*See* Exhibits SCE-SBUA-1 and SCE-SBUA-2).

9.2. Corporate Environmental Services

For SCE's Corporate Environmental Services' (CES) 2018 O&M test year, SCE forecasts $10.618 million for Accounts 920/921,[1120] $3.493 million for Account 921,[1121] and $1.991 million in OpX savings in Accounts 920/921,[1122] for a total of $12.120 million.[1123] No party challenges SCE's O&M request,[1124] which the Commission should adopt.

With respect to SCE's O&M request for $3.493 million for Account 921 relating to the San Dieguito Wetlands and Wheeler North Reef, San Diego Gas & Electric (SDG&E) submitted testimony requesting recovery for their cost,[1125] which SCE does not dispute. SCE agrees with SDG&E's proposed 20% share and overhead costs for marine mitigation with escalation, which is $991,000, $1.015 million, and $1.038 million (all nominal dollars) in 2018, 2019, and 2020, respectively.[1126]

For the capital project on well decommissioning, SCE agrees with ORA's proposal to use 2016 recorded of $532,000 instead of SCE's 2016 forecast of $651,000, resulting in a downward adjustment of $119,000.[1127] SCE thus agrees to ORA's 2016-2018 capital forecast of $1.864 million.[1128] No other party challenges SCE's CES's capital request, which the Commission should adopt.

9.3. Corporate Real Estate

Corporate Real Estate (CRE) plans, manages, and maintains SCE's electric and non-electric facility portfolio, comprising approximately 1,300 buildings and more than 7.3 million square feet of space. CRE's Operating and Maintenance (O&M) and capital forecasts are driven by the size and asset mix of the portfolio, the age and condition of the facilities, current regulations applicable to facilities, and business and operational needs.

[1120] *See* Figure IV-5 in Exhibit SCE-07, Vol. 2, p. 12 and Table II-8 in Exhibit SCE-23 Vol.1, p.12.
[1121] *See* Figure IV-6 in Exhibit SCE-07, Vol. 2A, p. 18 and Table II-9 in Exhibit SCE-23, Vol.1, p.13.
[1122] *See* Figure VI-7 in Exhibit SCE-07, Vol. 2, p. 24.
[1123] *See* Figure I-1 in Exhibit SCE-07, Vol. 2A, p. 1.
[1124] *See* Table II-8 in Exhibit SCE-23, Vol. 1, p. 12.
[1125] Exhibit SDG&E-01, pp. 4-5.
[1126] Exhibit SCE-23, Vol. 1, pp. 13-14.
[1127] *See* Table V-2 in Exhibit SCE-07, Vol. 2, p. 21 and Table II-7 in Exhibit SCE-23, Vol. 1, p. 11.
[1128] *See* Table II-7 in Exhibit SCE-23, Vol. 1, p. 11.

9.3.1. CRE O&M

SCE forecasts $50.987 million in CRE O&M expenses in Test Year 2018 to plan, manage, and maintain SCE's electric and non-electric facility portfolio.[1129] No parties contested SCE's 2018 CRE O&M forecast.[1130]

9.3.2. CRE Capital

CRE capital expenditures are necessary to provide a safe environment for all occupants of SCE facilities and a productive space for SCE's workforce. CRE's capital forecast includes four major programs: (a) Service Center Modernization Program, (b) Operational Support Program, (c) Blanket Capital Program and (d) IT Infrastructure and Equipment.[1131] SCE contests ORA's proposed 29% reduction of CRE 2017-2018 capital forecast. SCE further contests TURN's recommended reductions to and disallowances of certain CRE capital project forecasts through 2020.

9.3.2.1. The Commission Should Reject ORA's blanket reduction of Corporate Real Estate Capital Forecast from 2017-2018

While ORA takes no issue with SCE's justification for CRE capital projects or the reasonableness of the forecasts for those projects, ORA still recommends a uniform 29% reduction of the CRE capital forecast for 2017 and 2018, resulting in CRE capital forecasts of $117.164 million in 2017 and $156.903 million in 2018.[1132] ORA's recommendation is based on the SCE's underspend on CRE capital projects in 2016 (29% less than forecast) and its contention that the highest level of CRE capital expenditures from 2011-2016 was $125.505 million in 2014.[1133]

ORA's arbitrary use of a blanket reduction fails to address the particular needs for the projects that SCE discusses through its testimony. Nowhere does ORA dispute that the CRE capital projects remain necessary to support occupant safety, business and operational needs, compliance requirements, and facility preservation. Further, ORA does not provide any analysis specific to each CRE project or

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[1129] *See* Exhibit SCE-07, Vol. 03, p.1.
[1130] *See* Exhibit ORA-16, p. 11.
[1131] *See* Exhibit SCE-07, Vol. 03, p. 36.
[1132] *See* Exhibit ORA-16, p. 30. ORA also recommended adoption of CRE recorded capital expenditures for 2016 in place of SCE's 2016 forecast. SCE accepted this recommendation. *See* Exhibit SCE-23, Vol. 2, p. 3, lines 16-17. ORA did not address CRE capital forecasts for 2019 and 2020.
[1133] *See* Exhibit ORA-16, p. 30.

program forecast. Since the majority of SCE's facilities are greater than 30 years old and in substandard condition, SCE's strategic business and operational requirements create a pressing need to address capital maintenance of, and prudent upgrades to, the facilities.[1134]

Additionally, ORA's calculations of the level of capital expenditures for CRE capital projects are incorrect. ORA bases its calculations on SCE's response to a data request that only asked for amounts spent on CRE capital projects requested in the 2018 GRC.[1135] ORA's reliance on only those amounts spent on the CRE capital projects requested in the 2018 GRC does not take into account the other CRE capital programs and projects for which SCE recorded expenditures in prior years.[1136] In addition, ORA's data does not take into account other real estate programs and projects that were funded by other SCE operating units and executed by CRE. Since 2016, most of those "client-funded" real estate projects have been brought into CRE's responsibility for funding and execution.[1137] Outside of certain anomalous years (namely, 2012-2013[1138] and 2016[1139]), total CRE capital expenditures from 2010-2015, inclusive of the work funded and executed by CRE and "client-funded" work executed by CRE, averaged $176.665 million per year. This amount aligns with SCE's 2017-2018 CRE capital forecast.[1140]

With the commencement of SCE's Operational Excellence program in 2015, SCE initiated a transition process to: (a) refine CRE planning processes and building standards, (b) reduce CRE staff by over 50% (from 109 employees to 52 employees) and (c) integrate an external service provider for assistance with real estate maintenance and projects.[1141] This transition is the primary driver for the referenced underspend in CRE recorded expenditures in 2016. ORA's recommendation of a blanket 29% reduction of CRE capital forecasts in 2017 and 2018 would carry this abnormal underspend forward, even though this transition concluded in 2016, and SCE is currently proceeding with the CRE capital programs and projects as forecast for 2017 and 2018. Accordingly, SCE respectfully requests that

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[1134] *See* Exhibit SCE-07, Vol. 3, p. 40.
[1135] *See* Exhibit ORA-16, p. 28, footnote 122 and SCE-23, Volume 2, Appendix A, pp. 3-4 (SCE's response to ORA-SCE-Verbal-026, Q. 4.).
[1136] *See* Exhibit SCE-23, Vol. 2, p. 6.
[1137] *Id*.
[1138] *See* Exhibit SCE-23, Vol. 2, p. 7, lines 3-6.
[1139] *See* Exhibit SCE-23, Vol. 2, pp. 9-10.
[1140] *See* Exhibit SCE-23, Vol. 2, p. 6, Figure II-1. *See* also, Exhibit SCE-23, Vol. 2, p. 4, Table II-3 (SCE's 2017-2018 CRE capital forecast totals $350.570 million).
[1141] *See* Exhibit SCE-23, Vol. 2, pp. 9-10.

the Commission reject ORA's recommendation of a blanket 29% reduction to CRE capital forecasts from 2017-2018.

9.3.2.2. TURN's Recommendations Concerning SCE's Service Center Infrastructure Program Should Be Rejected

SCE operates 37 service centers across its service territory, housing multiple SCE Operating Units that work together to serve residential and business customers in their respective regions. The Service Center Modernization Program addresses the advanced age, deteriorated condition, and fitness for purpose deficiencies of 10 service centers that rank among SCE's most critical facilities. The service centers identified in this program have an overall facility condition index (FCI) of 13%-35% (poor to critical); the building configuration, property size, and other physical site limitations of those service centers do not properly support current work processes and equipment.[1142] TURN contests SCE's 2017-2020 forecasts for seven of the 10 service centers covered by the Program (including the IT Infrastructure and Equipment forecasts associated with each).[1143] TURN's recommendations are based on certain general arguments, plus arguments specific to the service center project. SCE addresses TURN's service center-specific arguments in subsequent sections.

TURN generally asserts that SCE's "track record" on GRC requests and service center spending warrants skepticism of SCE's commitment to the Service Center Modernization Program. Relative to Service Center Modernization funds authorized in the 2009 and 2012 GRCs, those funds were reallocated at the corporate level to projects that were deemed more critical for the delivery of safe and reliable service to SCE's customers.[1144] The Commission has recognized SCE should not be barred from seeking recovery for projects for which funding was previously authorized in prior rate cases and has authorized funds for CRE capital projects which were delayed or deferred from prior GRCs.[1145] While TURN questions the inclusion of service center projects in SCE's 2018 GRC application that were included in SCE's 2015 GRC application, TURN fails to acknowledge the impact arising from the fact

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[1142] *See* Exhibit SCE-07, Vol. 03, pp. 51-79.

[1143] TURN does not contest SCE's forecasts for the Barstow Service Center, Blythe Service Center, and Shaver Lake Service Center projects.

[1144] *See* Exhibit SCE-23, Vol. 2, Appendix A, pp. A-82-83 for D.12-11-051, pp. 582-583. *See* also Appendix A, pp. A- 84-94 for 2012 GRC Exhibit SCE-01, pp. 43-53 (Worden's Testimony).

[1145] *See* Exhibit SCE-23, Vol. 2, Appendix A, p. A-95. (D.15-11-021, p. 346.)

that SCE's request was only granted in part (approximately $3 million per year compared to the approximately $10 million per year requested).[1146] Notwithstanding the authorization of one-third of SCE's requested funding, SCE prioritized modernizing its service centers and recorded $11.407 million in Service Center Modernization expenditures (and related IT infrastructure and equipment) in 2015 (including initiating the Shaver Lake, Ridgecrest and Bishop service center projects).[1147]

TURN also questions the FCI definitions applied by SCE (namely, good, fair, poor, and critical) based on differing definitions used by Parsons Engineering (a vendor SCE utilized to assess its facilities). However, SCE's FCI rating definitions are industry standard, widely accepted, and applied by owners of large and complex real estate portfolios and various government bodies, including the Los Angeles Unified School District and the U.S. Department of Interior.[1148] Moreover, the fact that Parsons Engineering applies its own definitions that vary from the industry standard does not change the actual FCI scores. Parsons Engineering uses the same method as SCE and the International Facilities Management Association to calculate FCI scores. Those FCI scores, regardless of the definitions applied, show the ratio of the cost of correcting identified deficiencies to the replacement cost for the facility in whole. The FCI scores of the seven service centers contested by TURN range from 17% (Poor) to 35% (Critical).

TURN also questions the higher forecasts for the service center modernization projects as compared to the forecasts presented in earlier GRCs. However, SCE's testimony and supporting workpapers in this GRC detail a substantially larger scope of work for the projects than the earlier iterations of those projects. The increase in Service Center Modernization projects forecasts are associated with SCE's subsequent discovery of greater levels of building deterioration and the need to address fitness for purpose deficiencies arising from operational needs.[1149] It remains more prudent to modernize service centers to support current and future customers for 40 to 50 years rather than to complete smaller scale modernizations every few years.

[1146] *See* Exhibit SCE-23, Vol. 2, Appendix A, p. A-96. (D.15-11-021, p. 324.)

[1147] Exhibit SCE-23, Vol. 2, Appendix A, pp. A- 97-98. (SCE's response to TURN-SCE-021, Q. 2.b Supplemental.)

[1148] Exhibit SCE-23, Vol. 2, Appendix A, p. A-99 for the International Facilities Management Association Facility Condition Index Definition; Appendix A, pp. A-60-61 for Excerpt of the Department of Interior Policy on Deferred Maintenance, Current Replacement Value and Facility Condition Index in Life-Cycle Cost Management and *See* Appendix A, pp. A-62-70 for Excerpt of the Los Angeles Unified School District-Facility Condition Assessment.

[1149] *See* Exhibit SCE-07, Vol. 03, pp. 55-59.

While TURN tries to take SCE to task for failing to provide a detailed calculation of customer benefits from the expanded scope of the projects, the Service Center Modernization Program seeks to increase worker safety and productivity and improve work methods. The benefits to customers involving gains in productivity, safety, and reliability over the 40- to 50-plus year life of the service center are not readily quantifiable. SCE's testimony explains how larger sites allow for safer circulation for workers, pedestrians, vehicles, and equipment and provide needed space for vehicle maneuvering and storage of parts and materials. Additionally, these service centers all serve a greater volume of customers than the volume existing when they were originally built. Accordingly, SCE respectfully requests that the Commission reject TURN's proposed reductions and adopt SCEs forecast of $189.686 million for 2017 to 2020.

9.3.2.2.1. Bishop Service Center

While TURN takes no issue with SCE's decision to relocate the Bishop Service Center,[1150] TURN contests SCE's forecast based on the lower amount forecast for modernization in the 2015 GRC.[1151] However, the project scope outlined in the 2018 GRC for the Bishop Service Center includes additional work not included in the 2015 GRC. The expanded scope of work includes: (a) constructing a pre-fabricated logistics building, (b) constructing a vehicle garage, a wash bay, a fuel station, and a metal truck canopy, and (c) adding a canopied hazardous material storage area.[1152] These items were all included in support of worker safety, regulatory compliance, and operational efficiency.[1153] Further, the 2015 GRC forecast for the Bishop Service Center did not include costs to drill and install a water well, which was later added to the project's scope due to a mandate received by SCE from the Inyo County Planning Department.[1154] As such, TURN's recommendation to reduce SCE's 2017-2018 forecast for the Bishop Service Center project should be rejected.

[1150] Exhibit TURN-01, p. 11, lines 4-5.
[1151] Exhibit TURN-01, pp. 11-12.
[1152] Exhibit SCE-07, Vol. 03, pp. 62-63.
[1153] *Id*. *See* also, Exhibit SCE-23, Vol. 2, p. 24.
[1154] *See* Exhibits SCE-07, Vol. 3 p. 63, SCE-23, Vol. 2, p. 25, lines 4-8 and SCE-23, Vol. 2A, p. 25, line 5.

9.3.2.2.2. Kernville Service Center

TURN recommends reductions to SCE's forecast for the Kernville Service Center project based on the higher forecast for modernization as compared to the 2015 GRC.[1155] As with the Bishop Service Center project, such a comparison is unsuitable due to the expanded scope of work forecast in the 2018 GRC. The additional work on the new site (namely, constructing a pre-fabricated logistics building, vehicle garage, wash bay, fuel station, metal truck canopy, canopied hazardous material storage area) supports worker safety, regulatory compliance, and operational efficiency.[1156] The 2015 GRC forecast for the relocation of this service center also did not anticipate substantially higher land acquisition costs due to limited availability of commercially zoned land parcels of five to ten acres.[1157] Accordingly, the Commission should adopt SCE's forecast for the Kernville Service Center project and reject TURN's proposed reduction.

9.3.2.2.3. Redlands Service Center

TURN's proposed reduction to SCE's forecast for the Redlands Service Center project is based on: (1) the forecast being higher than the 2015 GRC forecast and (2) TURN's dispute over population growth in the communities served.[1158] The 2015 GRC forecast for the Redlands Service Center was limited to renovation of buildings on the existing site.[1159] In contrast, the 2018 GRC forecast involves relocation to a newly purchased site, preparation of the site and construction of supporting facilities (including administrative building, logistics building, vehicle maintenance facility, wash bay, etc.).[1160] The relocation was necessitated by material deficiencies in the existing site, including insufficient office space, vehicle parking, and site storage, projected growth in activity arising from the upcoming Transmission transfer of the 33kv system to the territory, and anticipated population growth in the communities served.[1161] While TURN questions the findings of SCE's consultant (La Canada Design Group) concerning anticipated population growth, the California Department of Finance projects similar

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[1155] Exhibit TURN-02, pp. 12-13.
[1156] *See* Exhibits SCE-07, Vol. 3, p. 67 and SCE-23, Vol. 2, p. 28, lines 7-18.
[1157] Exhibit SCE-23, Vol. 2, p. 28, lines 19-23.
[1158] Exhibit TURN-02, p. 15-16.
[1159] Exhibit TURN-02-A-1, p. 58-59 (Excerpt from SCE's 2015 GRC testimony on Redlands Service Center project).
[1160] Exhibit SCE-07, Vol. 3, pp. 68-69.
[1161] Exhibit SCE-23, Vol. 2, pp. 34-35.

population growth in the cities and counties served by the Redlands Service Center.[1162] As such, the Commission should reject TURN's proposed reduction to SCE's forecast for the Redlands Service Center project.

9.3.2.2.4. Ridgecrest Service Center

TURN's proposed reduction to the forecast for the Ridgecrest Service Center project is based on variations between SCE's request for this service center from the 2015 GRC and this GRC.[1163] While TURN questions why SCE did not notify the Commission of potential changes in the plans for this service center, the final scope of work requested in this GRC was not finalized under after the 2015 GRC decision issued. The 2015 GRC forecast for this service center only contemplated upgrades to certain buildings on the existing site.[1164] The forecast now includes additional work to improve the site, expand to an adjacent parcel and construct a logistics building, vehicle maintenance facility and wash bay.[1165] The expansion of the Ridgecrest Service Center is needed to serve SCE's customers effectively in this rural location by addressing various fitness for purpose deficiencies (inadequate space for material laydown, vehicle circulation and parking, insufficient water run-off and management, and inadequate space for material pre-fabrication and assembly) and allowing for improved vehicle circulation and safe paths of travel and proper vehicle maintenance facilities, materials storage and pre-fabrication facilities.[1166]

TURN's dispute over which label (i.e. "poor" or "fair") to apply to the FCI score of 25% does not change the fact that the Ridgecrest Service Center's buildings and grounds have been 25% consumed and must be addressed.[1167] The project is underway and expected to be completed by the end of 2017. SCE requests that the Commission adopts its forecast to modernize the Ridgecrest Service Center in support of safe and efficient service over the projected life of the facility.

[1162] Exhibit SCE-23, Vol. 2, pp. 32-33.
[1163] Exhibit TURN-02, pp. 17-18.
[1164] Exhibit TURN-02-A-1, p. 92 (Excerpt from SCE's 2015 GRC testimony on Ridgecrest Service Center project).
[1165] Exhibit SCE-07, Vol. 3, pp. 70-71.
[1166] Exhibit SCE-23, Vol. 2, pp. 37-38.
[1167] Exhibit SCE-23, Vol. 2, p. 37.

9.3.2.2.5. San Joaquin Service Center

TURN's proposed reduction to SCE's forecast for the San Joaquin Service Center project relies on the increased amount of the forecast (as compared to the 2012 GRC and 2015 GRC) and disputes over the FCI score and projected growth in the communities served.[1168] Contrary to TURN's claims that this project has been "moribund" since the 2012 GRC, SCE planned and completed capital maintenance at the San Joaquin Service Center when 2012 GRC funds were reallocated and the 2015 GRC request for Service Center modernization projects was not granted as requested.[1169] While this capital maintenance investment addressed some deferred maintenance, the current forecast for this project includes modernization work (namely, constructing an additional service bay, wash bay, and truck and fuel island canopy) to support safety, compliance and operational needs.[1170]

Notwithstanding TURN's skepticism over the ability of SCE personnel to report on regional growth in the communities they serve, those projections are validated by the California Department of Finance which similarly projects growth in the cities and communities served by the San Joaquin Service Center.[1171] As such, the Commission should reject TURN's proposed reduction to SCE's forecast for the San Joaquin Service Center project.

9.3.2.2.6. Santa Ana Service Center

TURN recommends disallowing SCE's forecast for the Santa Ana Service Center project based upon SCE's requests in prior GRCs and lack of spending in relation thereto.[1172] While SCE acknowledges that 2009 and 2012 GRC funds were reallocated to other areas, SCE did not proceed with the project as proposed in the 2015 GRC because only a portion of the funds requested for multiple service center modernization projects was authorized.[1173] The Santa Ana Service Center is 56 years old and situated in a heavily populated, urban location where there are significant service demands.[1174] The Santa Ana Service Center ranks high on the Asset Priority Index (API) list at 21 out of 1,300

[1168] Exhibit TURN-02, pp. 19-21.
[1169] Exhibit SCE-23, Vol. 2, p. 40.
[1170] Exhibits SCE-07, Vol. 3, p. 73 and SCE-23, Vol. 2, pp. 40-41.
[1171] Exhibit SCE-23, Vol. 2, pp. 41-43.
[1172] Exhibit TURN-02, pp. 21-22.
[1173] Exhibit SCE-23, Vol. 2, p. 45.
[1174] *Id.*

facilities.[1175] The scope of work proposed in this GRC is expanded from prior GRCs and includes constructing a new administrative building, logistics building and laydown area and improving building systems.[1176] The benefits gained from completing the project include: (a) safer vehicular ingress/egress and paths of travel for employees, visitors and customers, (b) improved work environments for employees, and (c) a more secure facility overall.[1177] SCE requests that the Commission adopts its forecast for modernization of the Santa Ana Service Center.

9.3.2.2.7. Santa Barbara Service Center

TURN recommends no funding for SCE's Santa Barbara Service Center project on the grounds that the costs of the project outweigh the benefits gained.[1178] SCE's decision to relocate the Santa Barbara Service Center arose primarily from negative impacts on power restoration time due to its distance from the customer base and supporting workforce.[1179]

Contrary to TURN's contention that SCE only considered service center relocation to address those issues, SCE considered a wide range of potential alternatives.[1180] However, relocation of the service center proved the only viable option that addressed the primary drivers of improving power restoration times and addressing staffing issues. Because the vast majority of outages occur in the region south of the current service center location and nearly all of its employees reside in this same region, relocation eliminates significant delays arising from traversing back and forth between outage locations and the existing site.[1181] By relocating the service center, SCE projects substantial improvement in restoration time.[1182] Additionally, the current location presents a staffing challenge due to the dearth of affordable housing in the surrounding community with a significant percentage of unfilled positions in key technical positions and high turnover rates.[1183] These staffing issues have forced SCE to pull

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[1175] Exhibit SCE-07, Vol. 3, p. 74.
[1176] Exhibit SCE-07, Vol. 3, p. 75.
[1177] Exhibit SCE-23, Vol. 2, p. 46.
[1178] Exhibit TURN-02, pp. 22-26. While TURN also raised issues relating to abandoning buildings on the site, SCE corrected earlier testimony that mistakenly implied that SCE did not own the buildings at the site. *See* Exhibit: SCE-07, Vol. 3, p. 77 and SCE-23, Vol. 2, p. 50, lines 1-8.
[1179] Exhibit SCE-07, Vol. 3, p. 76.
[1180] Exhibit SCE-23, Vol. 3, p. 49 and Appendix A, pp. A-180-199 (Santa Barbara Service Center GRC Capital Forecast Presentation).
[1181] Exhibit SCE-23, Vol. 2, p. 50.
[1182] *Id*.
[1183] Exhibit SCE-23, Vol. 2, p. 50-51.

resources from other areas and retain more costly contractors to meet work demands.[1184] SCE has considered personnel incentives to try to address these staffing issues. But such incentives are unworkable due to the represented nature of the impacted positions and the difficulty in structuring those incentives to cost-effectively compel remaining at the current location of the Santa Barbara Service Center.[1185] Accordingly, SCE requests that the Commission adopt its forecast for relocation of the Santa Barbara Service Center to improve service to the customers in the district.

9.3.2.3. TURN's Recommendations Concerning the Storage of Critical Electrical Equipment Spares Project Should Be Rejected

TURN recommends no funding for SCE's Storage of Critical Electric Equipment Spares Projects on the grounds it would not be cost-effective.[1186] Primary drivers for this project include the completion of the Chino Hills 500kV underground transmission line (operational in 2016) and SCE's need to maintain readily available critical spares for this line that will not be compromised by the elements at the time they are needed. The manufacturer's guidelines for critical spares affiliated with the transmission line support storage of certain critical spares, including cable reels, splices, terminations and related accessory kits, in an environmentally controlled, indoor space.[1187] Secure, indoor storage also helps mitigate risks associated with theft or sabotage.[1188] The proposed storage will house critical spares for this transmission line and for distribution and transmission emergent restoration work throughout SCE's 50,000 square-mile service territory.[1189]

TURN's references to SCE's 2011 Critical Spares Workstream project, dealing with process efficiencies for sites already used for storage of spare parts and equipment, do not detract from the needs for this project.[1190] This project focuses on critical spares needed for the Chino Hills 500kV underground transmission line, the only underground transmission line of this magnitude in the United States. Such spares are specially made and require significant lead time to acquire, and mitigating the risks of storing critical spares where they are exposed to elements, such as wind, heat, rain, and sunlight.[1191] The

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[1184] *Id.*
[1185] Exhibit SCE-23, Vol. 2, p. 51.
[1186] TURN-02, pp. 26-28.
[1187] Exhibit SCE-23, Vol. 2, p. 55-56.
[1188] Exhibit SCE-23, Vol. 2, p. 56.
[1189] Exhibit SCE-23, Vol. 2, Appendix, p. A-204.
[1190] Exhibit SCE-23, Vol.2, pp. 56-57.
[1191] *Id.*; Exhibit SCE-23, Vol. 2, Appendix, p. A-203; SCE, Bauder, Tr. 8/1001:22-1002:5.

financial impact from the premature replacement costs due to the equipment's exposure to the outdoor elements (weather, ultra-violet rays, animals, theft etc.) and the negative consequences arising from customers being subjected to outages for extended periods because critical spares in operating condition are not readily available can be significant, even if they are difficult to calculate at this time.[1192] Given the safety, security, and reliability benefits that accrue from this project, SCE requests that the Commission adopt its 2016 recorded capital expenditures and 2018-2019 forecast of $11.314 million for the Storage of Critical Electrical Equipment Spares project.

9.3.2.4. TURN's Recommendations Concerning SCE's Blanket Programs Should Be Rejected

9.3.2.4.1. Non-Electric Capital Maintenance

The Non-Electric Capital Maintenance Program includes seven categories of maintenance work at SCE's non-electric facilities: (1) Electrical/Fire Systems, (2) Fencing and Walls, (3) Flooring, (4) HVAC, (5) Paving, (6) Roof Repairs, and (7) Other Repairs. TURN recommends a $32.549 million reduction of SCE's 2016 recorded and 2017-2020 forecast for Non-Electric Capital Maintenance by relying solely upon SCE's 2016 recorded expenditures for Non-Electric Capital Maintenance ($14.305 million) and arguing that this level of spending should be sufficient in future years.[1193] TURN's position is solely based on its interpretation of how SCE was able to achieve an overall portfolio FCI score of 16% by the end of 2015 and the reasons for a lower level of spending than forecast in 2016 on Non-Electric Capital Maintenance.[1194]

From 2011-2015, SCE spent $157.513 million, or an average of $31.503 million per year, on Non-Electric Capital Maintenance.[1195] SCE requests $108.803 million, or an average of $21.761 million annually, in Non-Electric Capital Maintenance from 2016-2020.[1196] TURN's proposal would reduce 2016-2020 funding for Non-Electric Capital Maintenance to an amount less than half of SCE's average annual recorded spending on Non-Electric Capital Maintenance from 2011-2015.[1197] Contrary to

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[1192] Exhibit SCE-23, Vol.2, p. 57
[1193] Exhibit TURN-02, pp. 34-35.
[1194] Exhibit TURN-02, p. 35.
[1195] Exhibit SCE-07, Vol. 03, p. 137, Table V-53.
[1196] Exhibit SCE-07, Vol. 03, p. 132.
[1197] Exhibit TURN-02, p. 35, lines 7-13. Figure 19 on the same page incorrectly referenced $13.800 million as 2016 recorded expenditures.

TURN's assumption that such a reduced level would address current maintenance needs, such a dramatic reduction to non-electric capital maintenance spending would cause SCE's non-electric portfolio to deteriorate, increase the risk of potential failures of facility systems and components, and increase future maintenance and repair costs.[1198]

The most recent calculations of the required system replacement costs show that, for the period of 2018-2027, approximately $47.000 million in annual capital maintenance expenditures are required to maintain the current facility condition (*i.e.,* a level FCI score) for SCE's non-electric portfolio of buildings and grounds.[1199] The following table summarizes SCE's and TURN's varying positions:

Non-Electric Capital Maintenance Capital Expenditures
Summary of SCE and TURN Positions
Nominal $000

Non-Electric Capital Maintenance	Annual Capital Expenditures (Nominal $000)
SCE's Calculated System Replacements	47.000
SCE's Average Spend (2011-2015)	31.503
SCE's 2016 Recorded and Average Forecast for 2017-2020	21.761
TURN's Recommendation for 2016-2020	15.251

The lesser annual amount forecast by SCE for Non-Electric Capital Maintenance already takes into account the benefits gained from other facility renewal programs in the CRE capital forecast that will contribute to maintaining the current FCI level.[1200] As such, SCE's Non-Electric Capital Maintenance forecast is the minimum level maintaining the non-electric facility portfolio in its current operating condition and to avoid deterioration and associated reduction of the FCI level. In order to perform the maintenance work needed to keep its non-electric facilities in safe and reliable operating condition, SCE requests the Commission approve SCE's 2016 recorded capital expenditures and 2017-2020 forecast of $108.803 million for Non-Electric Capital Maintenance.

[1198] Exhibit SCE-23, Vol. 2, p. 62.
[1199] Exhibit SCE-23, Appendix A, p. 218.
[1200] Exhibit SCE-23, Vol. 2, p. 62.

9.3.2.4.2. Substation Capital Maintenance

SCE forecast $69.134 million for Substation Capital Maintenance from 2016-2020, or an average of $13.827 million annually.[1201] TURN recommends a Substation Electric Capital Maintenance forecast from 2016-2020 of $49.890 million, $21.940 million less than SCE's original forecast.[1202] TURN assumes that, since spending on substation capital maintenance increased significantly in 2014-2015 and then declined in 2016, this decline shows any deferred maintenance issues have been cured and the 2016 level of spending should be sufficient for future needs.

The $37.311 million incurred for substation capital maintenance from 2014-2015 (an average of $18.656 million per year) resulted from SCE's assessment of 31 *occupied* substations that showed FCI scores for these facilities averaging 25.06% (or "Poor" condition) and immediate spending to address the most urgent deficiencies found in this assessment.[1203]

As noted above, CRE's 2016 spending levels were abnormally low primarily because of a significant reduction in CRE staff and SCE's transition of facility project management to a managed service provider. Hence, this level of spending did not indicate the need for Substation Capital Maintenance is "tailing off" as TURN indicates.[1204] Continuing assessment of SCE's approximately 900 *unoccupied* substations has shown preliminary FCI scores ranging from 10.48% to 66.98%, with an average score of 49.94% or "critical."[1205] TURN's proposed annual average of $9.978 million from 2016-2020 is not sufficient to address deficiencies that have been, and will continue to be, identified. SCE respectfully requests that the Commission approve SCE's $71.830 million request for Substation Capital Maintenance from 2016-2020 (incorporating 2016 recorded expenditures).

9.3.2.4.3. Various Major Structures

The Various Major Structures program (VMS) funds projects that are unplanned or emergent, including those triggered by regulatory changes, environmental conditions and events (e.g. drought and wildfires), facility system breakdowns, and other significant facility failures. TURN recommends

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[1201] Exhibit SCE-07, Vol. 03, pp. 132-137. *See* also, SCE-23, Vol. 2, pp. 63-64 (2016 Recorded Expenditures for Substation Capital Maintenance were $10.766 million ($2.696 million over the original forecast).) SCE's position incorporates 2016 recorded expenditures in place of the 2016 forecast.

[1202] Exhibit TURN-02, pp. 35-38.

[1203] Exhibit SCE-23, Vol. 2, p. 65.

[1204] Exhibit TURN-02, p. 37.

[1205] Exhibit SCE-23, Vol. 2, p. 65.

$34.894 million for VMS, $48.805 million lower than SCE's forecast arguing that (a) SCE seems to be using VMS funding for projects that could have been planned, and (b) a six-year average of VMS expenditures is a better measure of future spending.[1206]

While SCE does not dispute that certain VMS projects require significant planning, TURN's perceived concern that such projects should not be characterized as emergent is unfounded. As detailed in its testimony, the examples cited by TURN all represent projects that presented safety and/or compliance risks, causing them to be reprioritized and initiated under VMS.[1207] TURN's recommended use of a six-year average of VMS expenditures should be rejected. TURN's approach fails to account for the significant increase in facilities and grounds that now fall under VMS. VMS now covers the buildings and grounds of substation and hydro facilities (over 1,100 additional buildings with an average infrastructure age of 30 years and covering approximately 1.1 million square feet), and assessments to date show FCI scores ranging from 40%-60%.[1208] Given the expanded coverage of VMS, SCE's forecast reasonably addresses the likelihood of emergent projects needed at those additional buildings and grounds, as well as the historical VMS spend for non-electric facilities. As such, SCE maintains its 2016 recorded and 2017-2020 forecast of $83.699 million for the Various Major Structures program is reasonable and the Commission should reject TURN's recommendation.

9.4. Corporate Health and Safety

The Commission should approve SCE's 2018 O&M forecast of $5.470 million for Account 925 expenses associated with SCE's Corporate Health & Safety Department.[1209] ORA raised the only issue when it opposed SCE's 2018 request for $700,000 in non-labor expenses to participate in the Electric Power Research Institute's (EPRI) Program 60 research on electric and magnetic fields (EMF).[1210] While ORA does not disagree that the program addresses key environmental health and safety issues,[1211] ORA is under the mistaken view that D.15-04-020 precludes SCE from seeking EPRI funding in the

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[1206] Exhibit TURN-02, pp. 38-41.
[1207] Exhibit SCE-23, Vol. 2, pp. 68-70.
[1208] *Id.* at p. 71.
[1209] Exhibit SCE-07, Vol. 4A, which updated SCE's 2018 forecast in Exhibit SCE-07, Vol. 4.
[1210] Exhibit ORA-16, p. 18, lines 15-16 and p. 19, line 14.
[1211] ORA's response to Question 2 of DR SCE-ORA-16 found on p. B-6 of Ex. SCE-23, Vol.1.

GRC[1212] and D.93-11-013 limited EPRI funding through 1999.[1213] As explained by SCE witness Mr. Paul Jeske, although D.15-04-020 declined to provide EPRI funding via EPIC, the Commission in that decision (a) affirmed funding for research institutes like EPRI, and (b) never indicated that funding would not be provided in the GRC.[1214] D.15-04-020 is specific to the EPIC account for technology demonstration and deployment (TD&D) activities, not with regard to research itself. In addition, as indicated by Mr. Jeske, the CPUC has authorized EPRI funding in SCE's prior GRC proceedings, which demonstrates that the CPUC has funded EPRI past 1999 in SCE's GRCs.[1215] As such, the Commission should approve SCE's 2018 O&M forecast of $5.470 million for Account 925, which includes SCE's 2018 request of $700,000 so that SCE can participate in the EPRI Program 60 research program.

9.5. Corporate Security

SCE accepted ORA's recommendations to adjust Corporate Security's capital forecast for 2016 to correspond with 2016 recorded capital expenditures of $19.261 million in order to narrow the issues that must be litigated to conclusion in this case.[1216] No other recommendations for adjustments to SCE's O&M or Capital forecasts for Corporate Security were made by ORA or any other party.

9.6. Supply Management

SCE accepted ORA's recommendation to adjust Supply Management's capital forecast for 2016 to correspond to 2016 recorded capital expenditures of $198,000 in order to narrow the issues that must be litigated to conclusion in this case.[1217] No other recommendations for adjustments to Supply Management's O&M or Capital forecasts were made by ORA or any other party.[1218]

[1212] Exhibit ORA-16, p. 20, lines 3-12.
[1213] ORA's response to Questions A.1.d.2 and A.1.e of DR SCE-ORA-22 found on p. B-22 of Ex. SCE-23, Vol. 1.
[1214] Exhibit SCE-23, Vol. 1, pp. 18-20.
[1215] Exhibit SCE-23, Vol. 1, pp. 21-22.
[1216] *See* Exhibits ORA-16, p. 49 and SCE-23, Vol. 1A, Table V-19.
[1217] *See* Exhibits ORA-16, p. 49 and SCE-23, Vol. 1A, Table V-19.
[1218] Although Small Business Utility Advocates (SBUA) submitted certain recommendations concerning Business Resiliency's capital forecast (*See* Exhibit SBUA-02, pp. 21-24) and SCE submitted rebuttal testimony addressing SBUA's recommendations (*See* Exhibit SCE-23, Vol. 1, pp. 7-9), SBUA and SCE entered into stipulations resolving the issues between them during the evidentiary hearings (*See* Exhibits SCE-SBUA-1 and SCE-SBUA-2).

9.7. Supplier Diversity

No party contested SCE's Supplier Diversity's O&M forecast.[1219] The National Diversity Coalition (NDC), however, recommended that SCE set aspirational goals of 42.9% for outside contracting and procurement spend from diverse business enterprises (DBEs) and 25.5% for minority business enterprises (MBEs), based on SCE's three-year average (2013-2015) performance.[1220] As indicated by SCE witness Shari Schuffels, Section 8 of General Order (GO) 156 specifies that each utility (not the Commission or another party) determine its short, mid, and long term goals for the use of DBEs.[1221] And, in SCE's prior GRC proceeding, the Commission affirmed that the utilities are the ones who set voluntary goals.[1222] SCE is committed to supplier diversity and, for the past four years, SCE has achieved a DBE spend percentage of over 40%, thus exceeding the 21.5% supplier diversity goal set forth in Section 8 of GO 156.[1223] Given the above, the Commission should reject NDC's proposal.

9.8. Transportation Services

The Transportation Services Department (TSD) manages the SCE vehicle and equipment fleet which includes passenger cars, vans, pick-up trucks, forklifts, heavy-duty trucks with aerial equipment (buckets and cranes), loaders, tractors, stringing equipment, trailers, and helicopters.

9.8.1. Operating Costs

TSD's operating costs fall into four categories: Fleet Ownership, Fleet Maintenance, Fuel, and Aircraft Operations. These costs are charged back to other SCE Operating Units (OUs) that require and

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[1219] Exhibit SCE-23, Vol. 1, p. 30.

[1220] NDC's Prepared Testimony of Faith Bautista on the 2018 General Rate Case Application of Southern California Edison, pp. 24-28.

[1221] Exhibit SCE-23, Vol. 1, pp. 31-32.

[1222] "In summary, we do not adopt any specific new target goals for reporting companies today. Instead we strongly encourage each reporting company to annually assess current WMDVBE spend and set their own voluntary numerical goals by looking to other utilities with successful programs. Whether it is a five-year plan to achieve 40% aggregate spend, or a three-year plan to grow MBEs by 25%, or Latino businesses by 10% per year, each company has room to improve and we strongly support a numerical commitment by which the utilities challenge themselves, and the Commission and public can measure the effectiveness of each utility's actions. We agree with the Staff recommendation that these voluntary targets be implemented on a gradual and increasing basis over time." D.11-05-019, pp. 29-30 (emphasis added).

[1223] Exhibit SCE-23, Vol. 1, p. 31.

utilize fleet support and embedded within the O&M and capital forecasts of those OUs. TSD's testimony does not separately request recovery for them.[1224]

9.8.1.1. Non-Fuel Operating Costs

SCE forecasts $109.381 million (nominal) in Test Year 2018 for TSD's non-fuel operating costs comprising the following categories: Fleet Ownership, Fleet Maintenance, and Aircraft Operations.[1225] TSD's non-fuel operating costs were forecast in nominal dollars using an itemized forecast methodology that took into account the projected fleet needs of each of the SCE OUs served (including T&D, Customer Service, Power Procurement and Operational Services.)[1226] TURN recommends a 2018 forecast of TSD's non-fuel operating costs by using a four-year average of SCE's recorded costs in nominal dollars from 2013-2016 as TSD's non-fuel operating costs have held relatively steady.[1227]

In rebuttal, SCE agreed to accept TURN's recommendation, subject to the use of constant dollars.[1228] TURN utilized nominal dollars to yield a forecast of $102.420 million.[1229] As TURN's recommendation applies an averaging methodology to historical operating costs, such a methodology should be applied to constant dollar historical expenses because those costs are normalized for comparison. Specifically, converting the historical costs to 2015 constant dollars normalizes escalations in spend due to inflationary pressures. When TSD's historical non-fuel operating costs are normalized to constant dollars, a four-year average of $103.072 million (2015 constant dollars) is derived from years 2013-2016.[1230] SCE requests that the Commission conclude that SCE's modified forecast of $103.072 million in TSD non-fuel operating costs for Test Year 2018 is reasonable.

9.8.1.2. Fuel Operating Costs

TSD's fuel operating costs consist of costs to procure gas, diesel, oil, propane and fuel pumping services. These fuel costs are also charged back to other SCE OUs, and TSD's testimony does not separately request recovery for them. SCE utilizes the Department of Energy's Energy Information Administration (EIA) Annual Energy Outlook to forecast gas and diesel fuel costs. While SCE accepted

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[1224] Exhibit SCE-07, Vol. 7, pp. 1-2
[1225] Exhibit SCE-23, Vol. 1, p. 37 (Table VII-25).
[1226] Exhibit SCE-07, Vol. 7, pp. 11-13; *See* also, SCE Guntrip Tr. 8/1050:14 – 1051:19.
[1227] Exhibit TURN-12, p. 40.
[1228] Exhibit SCE-23, Vol. 1, p. 38.
[1229] Exhibit TURN-12, pp. 39-40.
[1230] Exhibit SCE-23, Vol. 1, pp. 37 (Table VII-25) and 38.

TURN's recommendation to use updated EIA projections to forecast gas and diesel fuel costs,[1231] SCE contests TURN's recommendation to remove the outside fuel pumping service costs of $1.55 million (nominal) for Test Year 2018.

Refueling, checking fluid levels and performing additional vehicle safety checks on SCE vehicles must be performed, whether by TSD staff or contract labor.[1232] SCE initially went to contract labor to perform fuel pumping services due to a significant reduction in TSD staffing.[1233] Absent use of such contractor labor, TSD would need to add staff and reacquire and maintain more diesel fuel trucks to conduct this activity in-house.[1234] On balance, the use of contract labor is more cost effective than the use of TSD staff.[1235] Although SCE service centers have fuel storage and pumping facilities on site, such facilities remain needed for emergencies and off-hour refueling.[1236] Their existence does not impact the need for regular refueling service and related vehicle inspections.[1237] Therefore, SCE respectfully requests the Commission to approve SCE's 2018 forecast of $15.654 million (nominal) for TSD fuel operating costs.

9.8.2. Capital

SCE accepted ORA's recommendation to adjust TSD's capital forecast for 2016 to correspond to 2016 recorded capital expenditures of $1.461 million, in order to narrow the issues that must be litigated to conclusion in this case.[1238] No other recommendations for adjustments to TSD's Capital forecast were made by ORA or any other parties.

9.9. Operational Services – Additional Issues

[1231] Exhibit SCE-23, Vol. 1, pp. 40-41.
[1232] Exhibit SCE-23, Vol. 1, pp. 41; SCE Guntrip, Tr. 8/1038:22 – 1039:8.
[1233] Exhibit SCE-23, Vol. 1, Appendix C, p. 2 for TURN-SCE-100, Question 9b; SCE, Guntrip, Tr. 8/1046:28 – 1047:13.
[1234] Exhibit SCE-23, Vol. 1, p. 41.
[1235] Exhibit SCE-23, Vol. 1, p. 42 (Table VII-27).
[1236] Exhibit SCE-23, Vol. 1, p. 42; SCE, Guntrip, Tr. 8/1040:13-28.
[1237] *Id.*
[1238] *See* Exhibits ORA-16, pp. 49-54 and SCE-23, Vol. 1, pp. 34-35.

10. ADMINISTRATIVE & GENERAL

10.1. Ethics and Compliance

10.2. Regulatory Affairs

10.2.1. Regulatory Affairs Labor: FERC Account 920/921

SCE forecasts $15.214 million of Test Year 2018 expenses for its Regulatory Affairs Department in FERC Accounts 920/921, a decrease of $0.881 million over recorded 2015 cost levels.[1239] This decrease results from SCE's efforts to achieve efficiencies, optimize spending, and reduce costs.[1240]

TURN proposes an additional reduction of $2.167 million to Regulatory Affairs Labor FERC Account 920/921, over 2015 recorded cost levels.[1241] TURN bases this recommendation on an incorrect assumption that SCE included 18 employee vacancies in its Test Year 2018 forecast.[1242] SCE did not include any employee vacancies in its Test Year 2018 forecast.[1243] SCE based its forecast on actual recorded 2015 costs for 141 SCE employees, who were working during that year.[1244] SCE further adjusted its Test Year 2018 forecast to make it lower than 2015 recorded labor costs to reflect a head count reduction in fall of 2015.[1245] TURN's proposed subtraction of 18 "fictional employees" from SCE's 2015 recorded costs associated with 141 SCE employees, who were actually working in 2015, would cripple Regulatory Affairs' operations.[1246]

The Commission should adopt SCE's forecast, which is lower than 2015 recorded costs, due to SCE's efforts to achieve efficiencies, optimize spending, and reduce costs. The Commission should reject TURN's adjustment of this forecast based on an untrue and unreasonable deduction that SCE included 18 "fictional employees" in its forecast.

[1239] *See* Exhibit SCE-24, Vol. 01, pp. 1-6.
[1240] *Id.*
[1241] Exhibit TURN-07, p. 5, lines 12-21.
[1242] Exhibit SCE-24, Vol. 01, p. 5, line 29 – p. 6, line 10.
[1243] *Id.* p. 2, line 23–p. 3, line 2.
[1244] Exhibit SCE-24, Vol. 0,1p. 2, lines 24-26 and p. 6, lines 14-16.
[1245] *Id* p. 5, line 29–p .6, line 7 and Appendix B.
[1246] *Id.* p. 6, lines 14-16.

10.2.2. Regulatory Affairs – Integrated Planning Power Procurement: FERC Account 557

SCE forecasts $10 million of labor and non-labor expenses for Test Year 2018 for Integrated Planning Power Procurement, FERC Account 557.[1247] SCE used the Last Recorded Year as the forecast method.[1248]

TURN proposes to reduce SCE's forecast by $1.590 million associated with memberships and consulting expenses that relate to electric system modeling.[1249] TURN bases this proposal on the false assumption that these costs are associated with the discontinued Project Development Division ("PDD").[1250] To the contrary, SCE's forecast did not include any money supporting PDD functions.[1251] The $1.590 million relates to membership and consulting expenses associated with electric system modeling.[1252] While, in the past, SCE may have used these membership dues and consulting funds to examine future sites for peaker plants or utility-scale solar sites, SCE now uses them to conduct system-wide analysis for increased Renewables Portfolio Standard ("RPS") requirements.[1253] In addition, there are some modest non-labor costs associated with travel and meals for Integrated Planning Power Procurement employees.[1254]

The Commission should adopt SCE's reasonable forecast based on 2015 actual recorded costs. The Commission should reject TURN's adjustment based on a false premise that it includes discontinued PDD costs.

10.3. Corporate Communications

10.3.1. Corporate Communications Operations Labor: FERC Account 920/921

SCE forecasts $5.071 million of Test Year 2018 expenses for its Corporate Communications Operations Department in FERC Accounts 920/921, a decrease of $2.684 million over recorded 2015

[1247] *Id.* p. 7, lines 2-3.
[1248] *Id.* p. 7, lines 3-4.
[1249] *Id.* p. 8, lines 13-14.
[1250] Exhibit TURN-07, pp. 7-8.
[1251] Exhibit SCE-24, Vol. 01, p. 8, lines 13-14.
[1252] *Id*.
[1253] *Id.* p. 8, lines 16-20.
[1254] *Id.* p. 8 lines 20-24.

cost levels.[1255] This decrease primarily results from a head count reduction achieved through a department reorganization in 2016.[1256]

TURN proposes to reduce SCE's forecast for Corporate Communications Operations Labor FERC Account 920/921 by an additional $0.349 million.[1257] TURN bases this recommendation on an incorrect assumption that SCE included 4 employee vacancies in its Test Year 2018 forecast.[1258] SCE did not include any employee vacancies in its Test Year 2018 forecast.[1259] SCE based its forecast on actual recorded 2015 costs, less an OpX adjustment for a reduction of 27 employees that occurred in 2016.[1260] SCE adjusted its Test Year 2018 forecast to make it lower than 2015 recorded costs to reflect a head count reduction in 2016.[1261] TURN's proposed subtraction of the costs of 4 "fictional employees" from SCE's 2015 recorded labor costs adjusted for a head count reduction in 2016 would impede the important work performed by this department and would have adverse effects on the company's internal and external communications.[1262]

The Commission should adopt SCE's forecast, which is significantly lower than 2015 recorded costs due to SCE's efforts to optimize efficiencies and improve productivity. The Commission should reject TURN's adjustment of this forecast based on an untrue and unreasonable deduction that SCE included 4 "fictional employees" in its forecast.

10.3.2. Corporate Communications - Outside Services: FERC Account 923

SCE forecasts $1,689 million for FERC Account 923 for: 1) ethnic media services; 2) communications measurement; and 3) communications quality assurance.[1263] This is a decrease of $1.134 million over 2015 recorded cost levels associated with OpX efficiencies.[1264]

TURN proposes to eliminate any funding for this function asserting that the costs in this FERC Account include compliance with Affiliate Transaction Rules that SCE was unable to isolate and

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[1255] *See* Exhibit SCE-24, Vol. 01, p. 10, lines 3-6.
[1256] *Id.* p. 12, lines 5-6. $2.44 million of the cost decrease is associated with the head count reduction.
[1257] *Id.* p. 10, lines 11-12.
[1258] *Id.* lines 13-14.
[1259] *Id.* p. 11, lines 19-23.
[1260] *Id.* line 25 – p. 12, line 2.
[1261] *Id*.
[1262] *Id.* p. 12, lines 4-11.
[1263] Exhibit SCE-24, Vol. 01, p. 12, lines 13-19.
[1264] *Id.* p. 13, lines 1-2.

remove.[1265] To the contrary, the costs in this FERC Account do not include any costs for compliance with Affiliate Transaction Rules.[1266] More than 90% of the costs in this FERC Account are costs for translation services.[1267] If the Commission eliminates this funding, SCE would be unable to continue essential work of communicating with ethnic customers in their own native language.[1268]

The Commission should adopt SCE's forecast, which is significantly lower than 2015 recorded costs, due to SCE's efforts to optimize efficiencies and improve productivity. The Commission should reject TURN's elimination of this funding because, contrary to TURN's assertion, there are no Affiliate Transaction Rules compliance costs included in SCE's forecast.

10.4. Local Public Affairs

10.4.1. Local Public Affairs – FERC Account 920/921

SCE forecasts $7.904 million of labor and non-labor expenses for Test Year 2018.[1269] The only party providing intervenor testimony for this FERC Account was NDC, which urged the Commission to require SCE to host at least five capacity building workshops per year for community-based organizations.[1270] In 2015, SCE discontinued capacity building workshops because they were not core to Local Public Affairs function and has no plans to resume them.[1271] The Commission should adopt SCE's forecast for this FERC Account.

10.4.2. Corporate Membership Dues and Fees – FERC Account 930

SCE forecasts $1.920 million of non-labor expenses for FERC Account 930 for the ratepayer funded portion of dues and memberships costs, based on the last recorded year after making certain concessions to ORA and TURN.[1272]

ORA recommends the same funding level of $1.177 million adopted in the Test Year 2015 GRC, a 40% reduction from SCE's request, based on the last recorded year of membership fees and dues.[1273]

[1265] Exhibit. TURN-07, p. 12.
[1266] Exhibit SCE-24, Vol. 01, p. 15, lines 14-25.
[1267] *Id.* lines 16-17.
[1268] *Id.* p. 17, lines 14-16.
[1269] *Id*. p. 19, line 2.
[1270] *Id*. lines 14-16.
[1271] *Id.* at p. 19, line 18– p. 20, line 2.
[1272] Exhibit SCE-24, Vol.01, p. 20, lines 4-6 and Table III-11.
[1273] *Id.* at lines 9-12.

TURN recommends an aggregate $1.805 million reduction to FERC Account 930 proposing to disallow all funding of memberships dues and fees for: the Edison Electric Institute ("EEI"), California Taxpayer Association, Business Roundtable, California Small Business Association, and California Small Business Roundtable.[1274] SCE disagrees with TURN's and ORA's positions; however, SCE's forecast of $1.920 million reflects concessions removing fees and memberships for a total of $52,595 for California Foundation on the Environment and the Economy, California Small Business Association, and Committee Encouraging Corporate Philanthropy.[1275]

Both ORA and TURN's recommendations are unreasonable. TURN asserts that these membership fees and dues support political activities that ratepayers should not fund.[1276] TURN's characterizations are incorrect because SCE removed costs associated with activities that should be borne by shareholders from the funding request.[1277] Moreover, SCE's rebuttal testimony describes at length the many ratepayer benefits associated with SCE's participation in EEI and the other organizations that these membership dues and fees support.[1278] For example, these membership dues and fees support SCE's participation in the California Utilities Emergency Association, whose mission is to provide emergency operations support for utilities.[1279] As another example, SCE's EEI dues support its participation in the National Response Event which facilitates the coordination of mutual assistance among electric investor owned utilities in the United States.[1280] These two examples are among many other EEI initiatives that benefit ratepayers.[1281]

The Commissions should adopt SCE's reasonable forecast based on 2015 actual recorded costs, as modified by the concessions that it made to TURN and ORA. The Commission should reject both ORA's and TURN's adjustments because they do not appropriately account for the ratepayer benefits associated with SCE's participation in these organizations.

[1274] *Id*. at p. 20, line14 through p. 21, line 6.
[1275] *Id*. at p. 21, lines 9-18.
[1276] *Id* at. p. 20 line 14 through p. 21, line 6.
[1277] *Id*. at p. 21, lines 20-22.
[1278] *Id* at pp. 22-26.
[1279] *Id.* at p. 24, line 17 through p. 25, line 2.
[1280] *Id*. at p. 22, lines 8-13.
[1281] *Id*. at p. 22, line 2 – p.23, line 25.

10.5. Financial Services

SCE's 2018 forecast for the Financial Services Department is as follows: (a) $43.3 million for Accounts 920/921; (b) $20.9 million for Accounts 923/930; and (c) $.331 million for Account 926.[1282] SCE's 2018 forecasts are already well below the 2011-2015 recorded costs. For 2018, SCE also forecasts $64.198 million in Account 927 (Franchise Fees),[1283] $11.258 million in Account 930 (Participant Credits),[1284] and $9.867 million in Account 926 (Participant Credits).[1285] In addition, SCE computed a company-wide weighted average A&G capitalization rate of 24.05 percent, which applied to the test year 2018 forecast of applicable A&G expense.[1286] And, SCE is proposing to use a P&B capitalization rate of 45.5 percent for the test year 2018 forecast of P&B capitalization.[1287]

TURN is the only party that raised any issues with respect to the Financial Services Department. As discussed in more details below, the CPUC should reject TURN's proposals to impose even deeper cuts to SCE's 2018 labor forecast for Accounts 920/921 and our 2018 non-labor forecast for Accounts 923/930.[1288]

10.5.1. Account 920/921 (Labor)

Significantly, SCE's recorded labor has steadily decreased from $64.0 million in 2011 to $42.9 million in 2015, and SCE's 2018 TY forecast of $38.5 million in labor expense represents an even further reduction to an already lean organization.[1289] TURN proposes to reduce SCE's 2018 TY labor forecast further by $2.308 million based on a February 2017 data request, where TURN determined that there were 22 vacancies in the Financial Services Department with an average salary of $104,907 million which should not be filled.[1290]

TURN's reduction should be rejected. SCE anticipates 367 employees in the Finance Service Department in 2018, and, as of May 31, 2017, there were only 17 vacancies in the Financial Services

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[1282] *See* Table I-1 in Exhibit SCE-08, Vol. 3, p. 2.
[1283] *See* Figure II-6 in Exhibit SCE-08, Vol. 3, p. 25.
[1284] *See* Figure II-7 in Exhibit SCE-08, Vol. 3, p. 29.
[1285] *See* Table II-8 in Exhibit SCE-08, Vol. 3, p. 31.
[1286] Exhibit SCE-08, Vol. 3, pp. 32-33.
[1287] Exhibit SCE-08, Vol. 3, p. 33.
[1288] Exhibit TURN-07, pp. 14-19.
[1289] *See* Table II-2 in Exhibit SCE-24, Vol. 2, p. 3.
[1290] 22 employees x $104,907 = $2.308 million. Exhibit TURN-07, pp. 15-16; Exhibit SCE-24, Vol. 2, p. 3

Department,[1291] which SCE is on track to fill by 2018.[1292] Moreover, existing vacancies do not mean an absence of work, as SCE has used supplemental workers, consultants, etc. to temporarily perform work due to the vacancies.[1293]

SCE has already made significant reductions in its own test year forecast to aggressively and continuously pursue operational effectiveness amid an increasingly complex financial regulation and accounting practices.[1294] To adopt TURN's additional reductions on top of SCE's own reductions would cripple an already lean organization and hinder the Finance Service Department's ability to perform essential financial services functions.

10.5.2. Accounts 923/930 (Non-Labor)

SCE's 2018 non-labor forecast of $20.9 million represents a 58% reduction from its 2015 recorded expense of $49.2 million.[1295] TURN proposes an additional 15% reduction for its 2018 non-labor forecast of $13.251 million (i.e., an overall staggering reduction of 73% from 2015 recorded).[1296] The difference is due to the forecasting methodology used by the parties to forecast expenses for the Outside Services component of this account, which results in different baselines to which SCE's OpX downward adjustment of $27.654 million is applied. Specifically, SCE uses the 2015 recorded as a baseline to forecast 2018 expenses (plus the downward adjustment, primarily due to OpX),[1297] while TURN uses a five-year average (2011-2015) as its baseline for the same OpX adjustment.[1298]

SCE's proposed OpX downward adjustment of $27.654 million for Outside Services is directly linked to the baseline that SCE applied it to (i.e., 2015 recorded). As stated by SCE witness Mr. Jeff Duran, "To be clear, the baseline, the reduction, and the forecast are inextricably linked together. A change to the baseline (i.e., using the five-year average instead of the 2015 last year recorded) would therefore necessitate a change in the reduction."[1299] By using the same OpX adjustment to a different

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[1291] *See* Exhibit SCE-24, Vol. 2, p. 5, which indicates that the 17 vacancies are as follows: Controller's (4 vacancies); Treasurer's (4 vacancies); Operational Finance & Risk Management (9 vacancies).
[1292] Exhibit SCE-24, Vol. 2, pp. 5- 6. SCE's aggressive hiring efforts are demonstrated by the fact that since 2016, SCE has reduced vacancies from 50 to 17. *Id.*
[1293] *Id.*
[1294] *Id.* p. 4.
[1295] *See* Table II-4 of Exhibit SCE-24, Vol. 2, p. 8.
[1296] *Id.*
[1297] *Id.* p. 9.
[1298] Exhibit TURN-07, p. 17; Exhibit SCE-24, Vol. 2, p. 10.
[1299] Exhibit SCE-24, Vol. 2, p. 10.

baseline, TURN inappropriately double counts a portion of SCE's proposed reductions by reducing the baseline and then again applying the same 2018 forecast downward adjustment.[1300] If the Commission were to adopt TURN's baseline based on a five-year average (which it should not), then a corresponding revision to the OpX downward adjustment is needed as well.[1301] Therefore, the Commission should reject TURN's 2018 non-labor forecast for the Outside Services component of Accounts 923/930 because it double counts the OpX downward adjustment, and it would compromise SCE's ability to perform essential functions, including SCE's ability to comply with CPUC and SEC audit mandates/requirements and federal and state tax codes.[1302]

10.6. Audits

SCE respectfully requests that the CPUC adopt its 2018 forecast of $8.657 million for Account 920/921, which is based on $5.873 million for labor expenses and $2.784 million for non-labor expenses.[1303] TURN accepts SCE's 2018 non-labor forecast but challenges SCE's 2018 labor forecast. For labor expenses, SCE proposes to have about the same number of auditors in 2018 as in year-end 2015, and thus SCE's 2018 labor forecast of $5.873 million is about the same as SCE's 2015 recorded labor cost of $5.617 million.[1304] TURN, however, proposes a 2018 labor forecast of $2.937 million, which is a staggering 52% reduction of SCE's already low 2015 recorded labor costs.[1305]

TURN's 50% reduction in audit staff threatens SCE's ability to perform essential auditing functions. From 2011-2015, SCE's Audit Service Department (ASD) has steadily reduced its Account 920 labor expenses from $8.717 million in 2011 to $5.617 million in 2015,[1306] dramatically reducing ASD's staff to 44 auditors by year-end 2015.[1307] Despite already being at the lowest level in the past five years, TURN proposes additional steep cuts by essentially cutting ASD's recorded 2015 labor spending by more than half. This would result in decimating an already lean ASD organization and causing SCE

[1300] Exhibit SCE-24, Vol. 2, p. 11.
[1301] *See* Figure II-3 in Exhibit SCE-24, Vol. 2, p. 12.
[1302] Exhibit SCE-24, Vol. 2, p. 13.
[1303] *See* Figure III-10, p. 40 of Exhibit SCE-08, Vol. 3.
[1304] Id.
[1305] Exhibit TURN-07, pp. 18-19; Table III-6, p. 14, of Exhibit SCE-24, Vol. 2.
[1306] *See* Figure III-10, p. 40, of Exhibit SCE-08, Vol. 3 and Table III-6, p. 14, of Exhibit SCE-24, Vol. 2 (SCE, Andersen). SCE's overall expense for Account 920/921 from 2011-2015 also shows a similar steady decrease from $11.018 million in 2011 to $7.3 million in 2015. Id.
[1307] Exhibit SCE-24, Vol. 2, p. A4.

to be unable to perform essential auditing functions. As indicated by SCE witness Evangeline Andersen, a 50% reduction in staff would force SCE to decrease its available audit hours by approximately 23,000 audit hours.[1308] SCE's ability to perform risk-based assurance projects relating to customer data protection, cybersecurity, operational and environmental health and safety, financial controls, and procedural audits would be compromised significantly.[1309]

Moreover, TURN's proposal is based on the incorrect assumptions that there are 28 vacancies that are unfilled and can be terminated, and that ASD could operate the department at that level of staffing. TURN's 2018 labor forecast of $2.937 million was calculated based on the incorrect assumption that ASD has 56 budgeted employees, 28 actual employees, and thus 28 vacancies that can be terminated.[1310] Using an average cost of $104,875 per employee, TURN applied this average cost to the 28 assumed vacancies to derive $2.937 million and reduced SCE's 2018 labor forecast of $5.873 million by this amount.[1311]

TURN's conclusion that there are 28 vacancies is based on data from two different time periods.[1312] Specifically, TURN relies on the 56 "budgeted employees" identified from SCE's Master Data Request MDR-07, Q. VII.13 (dated February 2016),[1313] and the 28 actual employees in 2017 from a March 2017 data request.[1314] Despite the February 2016 date visibly specified on the face of the MDR, TURN apparently misunderstood and believed the data to be more recent, namely, in the August/September 2016 time period when SCE posted the MDR on its GRC data base.[1315] While SCE regrets this misunderstanding, this does not change the fact that the reference to the 56 budgeted employees is stale and no longer applicable. SCE's 2018 labor forecast is based on the anticipated costs for 43 auditors in 2018[1316] (not 56), which is about the same number of auditors SCE had at the end of 2015.[1317] SCE's need for 43 auditors takes into account the compliance and risk based assurance work

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[1308] Exhibit SCE-24, Vol. 2, pp. 19-20.
[1309] *Id.*
[1310] Exhibit TURN-07, p. 18. SCE recreated TURN's table as Table III-7 in Exhibit SCE-24, Vol. 2, p. 17.
[1311] That is, TURN's 2018 labor forecast of $2.937 million is calculated as follows: $5.873 million - $2.9365 million = $2.9365 million. Exhibit TURN-07, pp. 18-19; Exhibit SCE-24, Vol. 2, pp. 14-15.
[1312] Exhibit TURN-07, p. 18 (recreated as Table III-7 in Exhibit SCE-24, Vol. 2, p. 17).
[1313] Exhibit SCE-24, Vol. 2, pp. A1-A2.
[1314] Exhibit SCE-24, Vol. 2, pp. A3-A4.
[1315] SCE, Menon, Tr. 14/1994-1995.
[1316] Exhibit SCE-24, Vol. 2, p. 18.
[1317] In 2015, SCE had 44 auditors. Exhibit SCE-24, Vol. 2, p. A4.

that SCE needs to perform, ASD's 2016 reorganization which reduced staff in order to make room to hire personnel with needed skillsets and expertise,[1318] ASD's current staff levels and hiring efforts, and SCE's expectation that it will be staffed with up to 43 auditors to carry out its critical mission.[1319] In order to carry out that critical mission while returning to a fully-staffed state, ASD was required to utilize external resources in order to augment the department's temporarily reduced level of staffing and manage workload.[1320]

More importantly, SCE believes that the discussion of the number for 2018 "budgeted employees" is a red herring since ASD's 2018 labor forecast is based on last year recorded expenses and the amount of audit hours needed SCE's annual audit plan, and not an itemized headcount budget.[1321] Reducing 2015 labor expenses in half, as TURN proposes, would decimate the already lean ASD, crippling its ability to provide assurance work and protect the interests of SCE's customers.

10.7. Enterprise Risk Management

10.8. Legal

SCE forecasts $104.331 million for the Legal Organization, consisting of $44.791 million for the Law Department, including Corporate Governance, $24.373 million for the Claims Department, $14.594 million for the Workers' Compensation Department and $20.573 million for Disability Management.

10.8.1. Removal of Costs Resulting From Alleged Imprudence

10.8.1.1 TURN's Recommendation to Remove Costs Allegedly Resulting from Imprudence Should be Rejected

TURN identifies five incidents of alleged imprudence, including the SONGS replacement steam generator project, the 2007 Malibu wildfire, 2015 outages in Long Beach, 2011 fatalities in San Bernardino, and the 2011 San Gabriel windstorm. TURN recommends removing over $12 million of Legal Organization costs in the Law and Claims Departments purportedly relating to such incidents.[1322]

[1318] Exhibit SCE-24, Vol. 2, p. 16.
[1319] Exhibit SCE-24, Vol. 2, p. 18.
[1320] Exhibit SCE-24, Vol. 2, p. 16.
[1321] Exhibit SCE-24, Vol. 2, pp. 17, 19.
[1322] Exhibit TURN-13, pp. 25-26.

TURN's recommendation to remove such costs should be rejected.[1323] First, these costs involve defending or responding to claims that arise in the ordinary course of operating an electric utility, a complex business enterprise. Accordingly, under traditional cost-of-service ratemaking, SCE should be allowed to recover from its ratepayers its reasonable defense and claims response costs. Second, although SCE has admitted certain statutory and regulatory violations in some of these matters (see below), the Commission has made no findings of imprudence. Third, removing the costs would create additional, after-the-fact shareholder penalties in matters that have already been finally resolved in Commission-approved settlements. This after-the-fact enhancement of penalties agreed to as components of settlements would discourage future settlements in Commission proceedings, which would be contrary to public policy.

Most of TURN's alleged imprudence-related costs represent TURN's estimate of costs of SCE's in-house legal staff.[1324] SCE does not track in-house personnel costs by matter or proceeding. TURN's assumption in estimating in-house costs to be disallowed, namely, that in-house resources are allocated to particular matters in the same percentage as the allocation of outside counsel resources in those matters bears to all outside spend is highly inaccurate and inflated by the spend in one atypical matter (SONGS), where no imprudence has been found.[1325] Importantly, except for one employee retained as a SONGS litigation project manager, SCE has not incurred any incremental in-house costs in the matters TURN identifies.[1326]

Under Commission precedent, SCE may recover reasonable costs of defense, including the defense of claims of imprudence.[1327] TURN focuses on several matters in which SCE acknowledged statutory or regulatory violations and equates this with imprudence. But in SONGS, the overwhelming driver of TURN's "imprudence cost estimate," SCE has not acknowledged violations of Commission regulations or decisions, nor has it been found imprudent.[1328]

[1323] Exhibit SCE-24, Vol. 3, pp. 7-11.

[1324] Approximately $10 million of the $12 million imprudence adjustment sought by TURN consists of in-house legal and claims expenses. Exhibit TURN-13, pp. 25-26.

[1325] Exhibit SCE-24, Vol. 3, pp. 10-11.

[1326] Exhibit SCE-24, Vol. 3, p. 10; SCE, Swartz, Tr. 14/2015 ("Our inside costs relate to the fact that we have a standing law department that deals with numerous matters. We are not staffing directly with respect to these matters versus other matters.")

[1327] D.03-02-035, p. 10, 2003 Cal. PUC LEXIS 93.

[1328] If SONGS costs are removed from TURN's imprudence cost calculation, costs allegedly arising from imprudence are reduced from 18.2% of costs to approximately 1%. Exhibit SCE-24, Vol. 03, p. 11.

In the other matters TURN lists, SCE has acknowledged certain statutory and regulatory violations. But TURN's assertion that violations of law equate to imprudence is incorrect. Prudence does not require perfection.[1329] As pointed out by SCE's General Counsel, Russell Swartz, and as the Commission has confirmed, whether costs in a particular case arise from imprudence is a fact-specific inquiry.[1330] And even if some of the costs associated with the identified non-SONGS matters could be deemed to have arisen from imprudence, each was the subject of enforcement proceedings. In Commission-approved "complete and final" settlements of these proceedings, the parties agreed to substantial shareholder-funded penalties and system enhancements but, with one exception, did not require shareholder funding of legal or other internal costs.[1331] TURN, which could have intervened in such proceedings, did not do so. Instead it now seeks what amounts to an after-the-fact incremental shareholder penalty. As Mr. Swartz testified, SCE resolved these matters with the expectation of achieving closure. SCE, and in fact other Commission-regulated utilities, would have little incentive to resolve matters if they remain potentially liable for substantial additional penalties in future proceedings. The Commission encourages settlement precisely for this reason.[1332]

10.8.1.2 TURN's "Non-Forecast" Recommendation Is Unnecessary and Should Be Rejected

Asserting "SCE failed to have a systematic process for removing costs resulting from imprudence," TURN would have the Commission direct SCE to revise its guidance documents to specify the removal of costs resulting from imprudence.

While the scope of its proposal is not entirely clear, TURN may be recommending removing all costs when SCE acknowledged a statutory or regulatory violation, regardless of whether the violation involves imprudence. This would be unwise regulatory policy. It would deprive SCE of the ability to defend itself. Moreover, as explained by Mr. Swartz and confirmed by the Commission (see citations above), TURN's blanket approach would be improper. Each situation must be evaluated on its facts.

[1329] D.14-06-007, p. 36 (prudence "is not a 'perfection' standard").

[1330] SCE, Swartz, Tr. 14/2008-2010; *Re Pacific Bell*, D.87-12-067 at p. 36, 27 CPUC2d 1 (determining prudence involves a "case-by-case analysis" and an "individualized and particularized view of the evidentiary record").

[1331] In the Malibu Fire settlement, SCE agreed to remove outside counsel costs from its GRC forecasts and, as TURN acknowledges, has done so. Exhibit SCE-24, Vol. 3, p. 8 fn. 12.

[1332] D.17-07-004, p5 ("The Commission has long held a policy strongly favoring settlements, similar to that of other judicial bodies in the State of California and the United States . . . ").

TURN would apparently remove all costs in "any line of operations," which presumably would include, besides the Legal Organization, finance, regulatory, transmission & distribution. As noted, SCE did not (with the one exception noted above) incur incremental in-house law or claims costs for the incidents identified by TURN. The Commission has confirmed that the costs of time-tracking attorney time outweigh the benefits.[1333] But TURN's proposal would require tracking, not only of attorney time but also time for personnel in a wide range of Company operations.

Finally, TURN's proposal is unnecessary. SCE already carefully reviews its costs and removes items not appropriately included in its GRC. Its workpapers detail adjustments for such removals, including the removal of outside counsel costs for the Malibu Fire, an incident TURN identifies as involving imprudence, where SCE agreed as part of a settlement to remove such costs, and many other adjustments.[1334]

TURN's proposal to log and remove in-house costs allegedly associated with imprudence is impractical, vague, unduly burdensome and unnecessary. The proposal should be rejected.

10.8.2. Law Department

SCE forecasts $44.791 million for the Law Department: Law's FERC Accounts 920/921/923/925/928 and Corporate Governance's FERC Account 930. TURN and ORA challenge various aspects of the forecast for these accounts besides TURN's challenge based upon alleged imprudence addressed above. These challenges were addressed in detail in SCE's rebuttal testimony, and SCE briefly summarizes the evidentiary record below.

10.8.2.1 FERC Accounts 920/921 In-House

SCE forecasts $25.397 million for FERC Accounts 920 and 921. This forecast incorporates a reduction to in-house labor costs to reflect the results of the SCE Legal Organization Operational Excellence initiatives. ORA does not challenge SCE's forecast. TURN asserts that SCE's in-house labor forecast is based upon an inflated headcount and recommends a $3.669 million reduction. As pointed out in SCE's rebuttal, TURN is mistaken.[1335] SCE properly based its labor forecast on 2015 year-end authorized positions, reduced by the positions eliminated in 2016 from Operational Excellence

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[1333] Exhibit TURN-13, p. 18.

[1334] *See, e.g.,* Exhibit SCE-08, Vol. 04 WP, pp. 32-33 and pp.57-59 (adjustments removing numerous categories of outside counsel costs). The Malibu Fire is OU Adjustment 4. *Id.*

[1335] Exhibit SCE-24, Vol. 3, p. 6.

initiatives. This is SCE's current estimate of its 2018 headcount. SCE's analysis is sound and TURN's is flawed. Accordingly TURN's recommended reduction should be rejected.

TURN also challenges the factor used to allocate in-house corporate governance expenses to SCE, asserting that the 99% factor SCE used is incorrect. As SCE explained in its rebuttal, the 99% factor is based upon a Commission-approved methodology which SCE is correctly applying.[1336] TURN's challenge to this allocation should not be adopted.

10.8.2.2. FERC Accounts 923/925/928 Outside Counsel

SCE's adjusted forecast for these accounts is $15.292 million, representing a five-year average of recorded costs for the years 2011-2015.[1337] ORA recommends removing 2013 costs, claiming 2013 is an outlier year, resulting in a four-year average (2011-2012, 2014-2015) of $13.925 million, for a reduction of $1.367 million. TURN, citing an alleged downward trend in outside counsel costs, asserts last recorded year (2015) is the appropriate basis for the outside counsel forecast.

SCE's five-year average is appropriate to forecast outside counsel expenses. The Commission has held that such a method should be utilized where costs fluctuate from year-to-year and are influenced by forces beyond the control of the utility.[1338] Outside counsel represents a clear example of such costs. SCE's outside counsel costs vary based upon the incidence of class action lawsuits, large contract disputes, wildfires, and other unpredictable developments. California is a litigious state, which routinely sees an expansion of rights that form the basis for new claims that may be asserted in civil litigation.[1339] And the number of regulatory proceedings that SCE appears in has likewise not diminished. TURN cites a three-year downward trend in costs. However, has anything changed in the legal or regulatory environment to suggest a decrease in litigation of the type traditionally resulting in year-to-year cost variation? SCE does not believe so.[1340]

[1336] Exhibit SCE-24, Vol. 3, pp. 11-12.

[1337] SCE adjusted its forecast through an errata reflecting outside counsel costs it inadvertently failed to include and other costs it inadvertently failed to exclude. These adjustments were the subject of TURN's motion to strike SCE's errata. On September 6, 2017, TURN's motion was denied.

[1338] D.89-12-057, p. 15.

[1339] To take just one recent example, in July of this year the California Supreme Court issued a decision expanding the rights of plaintiffs pursuing Private Attorneys General Act (PAGA) lawsuits enforcing laws requiring employee meal and rest breaks. Under this recent decision, PAGA plaintiffs can now initiate such suits and engage in broad discovery without first making a threshold showing that the suit is meritorious. *Williams v. Superior Court* (2017) 3 Cal.5th 531.

[1340] Exhibit SCE-24, Vol. 3, p. 14.

The ORA and TURN recommendations should be rejected. ORA's proposal to remove 2013 is arbitrary. It would be just as rational to remove the low cost year. TURN's proposal to use last recorded year is also erroneous. Given the variability in its outside costs as new matters ebb and flow from year-to-year, SCE's forecast based upon a five-year average is appropriate and should be adopted.

10.8.2.3. FERC Account 930 Corporate Governance

SCE's forecast for this account is $4.1 million. ORA and TURN challenge the inclusion of costs for equity compensation paid to the Edison International and SCE Boards of Directors ("Board"). TURN additionally challenges the allocation of board of director costs to SCE based upon the same rationale used above in its challenge to the allocation to SCE of in-house Corporate Governance expenses. SCE acknowledges the Commission has rejected past requests to recover equity compensation paid to the Board. SCE continues, however, to believe that such compensation is appropriately recovered in rates for the reasons explained in its opening testimony.[1341] As explained above in the discussion of Corporate Governance in-house expenses, the factor used to allocate Board expenses to SCE is correct under the methodology prescribed by the Commission. TURN's and ORA's challenges to the Corporate Governance forecast should be rejected.

10.8.3. Claims

SCE forecasts $24.373 million for the Claims Department: FERC Accounts 920/921/924 (Administrative Expenses) and FERC Account 925 (Claims Reserves). ORA does not challenge the forecast for administrative expenses. TURN's challenge to such expenses is based upon alleged imprudence in respect of a number of Claims-related matters and, for the same reasons discussed above in relation to in-house counsel expenses, should be rejected.

SCE forecasts $21.348 million for Claims Reserves (FERC Account 925) based upon a five-year average of historical costs. ORA recommends "normalizing" this average by eliminating amounts associated with large claims for 2013 and 2014, resulting in a recommended reduction of $6.4 million. TURN recommends using the last recorded year (2015) where recorded costs were $6.978 million, plus an additional reduction for costs allegedly arising from alleged imprudence, resulting in a recommended total reduction of $16.370 million, or 77% percent of SCE's forecast amount.

[1341] Exhibit SCE-08, Vol. 4, pp. 18-20.

SCE's five-year average is appropriate to forecast claims reserves. As is the case for outside counsel costs, claims reserves fluctuate from year-to-year and are influenced by forces beyond SCE's control. SCE's rebuttal shows a recent 10-year history in which four of the 10 years with claims reserve cost levels were at or above the allegedly high cost years ORA wants to "normalize."[1342] Past Commission experience in which the Commission adopted a last recorded year forecasting method, in the 2009 and 2012 GRCs, resulted in wildly fluctuating amounts, a $35 million forecast adopted in the 2012 GRC and a $3.885 million forecast adopted in the 2009 GRC.[1343] In the 2015 GRC, the Commission stated, "[a] 5YA forecast is a reasonable approach to forecasting accounts with high variation in recorded costs."[1344] That approach is reasonable for this GRC. TURN's and ORA's challenges should be rejected.

10.8.4. Workers' Compensation

SCE forecasts $14.594 million for the Workers' Compensation Department, comprising $6.783 million in administrative expenses and $7.811 million in Workers' Compensation reserves. Neither TURN nor ORA challenges the administrative expense forecast. ORA does not challenge the reserve forecast for Workers' Compensation. SCE's forecast is based upon a three-year average of costs covering 2013-2015. TURN agrees an averaging method is appropriate for Workers' Compensation reserves and to the exclusion of years 2011 and 2012 but recommends a four-year average to include 2016, resulting in a recommended forecast reduction of $1.048 million. TURN's recommended inclusion of 2016 is inappropriate because costs in that year were unusually low and therefore not indicative of future trends.[1345] TURN's recommendation should be rejected.

10.8.5. Disability Programs

SCE forecasts $17.74 million for Disability Programs in the Test Year. This includes projected costs for short-term and long-term pay replacement benefits through the Comprehensive Disability Plan (CDP) and Long-Term Disability Plan, respectively. The forecast also encompasses assistance for employees with work restrictions in finding alternative or modified employment through the Return to Work Program. ORA's forecast is $16.9 million, based on SCE's 2015 Recorded/Adjusted Base Year

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[1342] Exhibit SCE-24, Vol. 3, p. 22.
[1343] Exhibit SCE-24, Vol. 03, pp. 23-24.
[1344] D.15-11-021, p. 313.
[1345] Exhibit SCE-24, Vol. 03, p. 28.

multiplied by SCE's escalation rate.[1346] TURN's forecast is $17.6 million. TURN takes a five-year average on a per-employee basis and bypasses the formula-based forecast found in our RO Model.[1347]

In D.15-11-021, the Commission adopted a mechanism (utilizing the RO Model) that considers forecast labor costs, employee headcounts, recorded benefit programs expenses and escalation rates; the Commission rejected a proposal to authorize spending based on the last recorded year.[1348] Consistent with this Commission guidance, SCE developed its Test Year 2018 projection for Disability Programs costs by utilizing forecast labor costs, employee counts, recorded benefit programs expenses and escalation rates.[1349]

SCE's implementation of Operational Excellence (OpX) efforts reduced employee headcount, and SCE's forecast of employee headcount reflects several years of experience implementing OpX initiatives. SCE's forecast methodology aligns SCE's Disability Programs forecast with the primary drivers for that program, the forecast number of eligible employees, and the forecast dollar costs per employee.

10.9. Property and Liability Insurance

10.9.1. Property Insurance

SCE accepts ORA's and TURN's recommended property insurance expense forecast of $14.070 million for Test Year 2018, because premiums in the property insurance market are now expected to remain stable for 2018.[1350]

10.9.2. Liability Insurance

SCE forecasts $92.427 million for total liability insurance expense in Test Year 2018.[1351] SCE based its request on an expert forecast of premiums, reflecting current insurance market pricing trends and actual loss experience, rather than on recorded historical cost.[1352]

[1346] Exhibit ORA-17, pp. 20-21.
[1347] TURN-07, pp. 27-28.
[1348] D.15-11-021, p. 274 ("SCE's basic approach of calculating per-eligible-employee costs, escalating those costs, and multiplying by the number of eligible employees is reasonable.").
[1349] *See* D.12-11-051, p. 473 (forecast based on per-employee costs is a reasonable method to capture demographic changes in the workforce).
[1350] Exhibit SCE-24, Vol. 4, p. 4, lines 1-6.
[1351] Exhibit SCE-08, Vol. 5C, p. 9, lines 9-10.
[1352] Exhibit SCE-24, Vol. 4, p. 5, lines 3-6.

ORA and TURN recommend using the Last Year Recorded forecast of $71.296 million for Test Year liability insurance expense.[1353] This recommendation fails to take into account that ongoing wildfire conditions throughout California put strong upward pressure on insurance premiums and are leading insurers to reduce or eliminate wildfire coverage in the state.[1354] For example, SCE renewed its general liability insurance in 2017 at a premium approximately 25% greater than the 2016 renewal.[1355] In addition, there still remain uninsured gaps in SCE's wildfire and non-wildfire insurance coverage from the 2017 renewal.[1356] SCE and Marsh anticipate more significant premium increases and more uninsured gaps in 2018.[1357]

The Commission has accepted SCE's use of the expert forecast method in the previous five rate cases, and there is no basis for changing to the Last Year Recorded methodology in this rate case.[1358] A review of the years 2011 through 2015 shows that the authorized level of rate recovery (based on the expert forecast method) was a much more accurate forecast of actual insurance expense than the Last Year Recorded method was.[1359] In fact, the total forecast error using the Last Year Recorded method was almost 13 times as much as the total forecast error using the traditional expert forecast method.[1360]

TURN wrongly asserts that SCE did not provide enough support for its expert forecast method.[1361] To the contrary, SCE's direct and rebuttal testimony, workpapers, and responses to over 100 data requests provide equivalent, if not more, support than what SCE supplied in prior rate cases and is very similar in the level of detail to information presented in PG&E's 2017 GRC workpapers.[1362]

The Commission should adopt SCE's reasonable forecast for liability insurance, which it reasonably bases on an expert forecast, reflecting current insurance market pricing trends and actual loss experience. The Commission should continue to accept the expert forecast method (as it has in the previous five rate cases) and reject ORA and TURN's recommendation to use the Last Year Recorded

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[1353] Exhibit ORA-17, p. 27, and Exhibit TURN-07, pp. 32-33.
[1354] Exhibit SCE-24, Vol. 4, p. 6, lines 2-5.
[1355] *Id*. lines 10-11.
[1356] *Id.* at lines 11-21.
[1357] *Id.* at lines 23-24
[1358] *Id.*, p. 11, lines 5-7.
[1359] *Id*. at pp. 7-8, specifically including Tables III-4 and III-5.
[1360] *Id*. at p. 7, lines 12-14.
[1361] Exhibit TURN-07, p. 29.
[1362] Exhibit SCE-24, Vol. 4, p. 9, lines 8-19.

method because the latter method does not reflect current insurance market conditions and has been very inaccurate historically.

10.10. Administrative & General – Additional Issues

11. RATEMAKING PROPOSALS

In its opening testimony,[1363] SCE presented several GRC-related ratemaking proposals that were associated with SCE's requested Commission-jurisdictional base-related revenue requirement. Other parties raised a number of issues about SCE's proposals. Further information regarding portions of contested proposals and forecasts are included within the sections of the brief that discuss the specific proposal. SCE provides an overview here for ease of reference.

SCE also attaches, as Appendix C, a spreadsheet that outlines each of the SCE memorandum or balancing account proposals that are uncontested. SCE respectfully requests that the Commission's Decision in this GRC approve each of the uncontested proposals.

11.1. Establishment of the DER Deferred Project Memorandum Account (DERDPMA)

SCE has withdrawn its request to establish the DERDPMA.[1364]

11.2. Establishment of the PUC 706 SCE Officer Compensation Memorandum Account (SOCMA)

SCE demonstrated that its proposal to establish this account should be adopted, consistent with Public Utilities Code Section 706, in compliance with a final decision in this GRC.[1365] SCE also showed why SBUA's suggested definition of "officer" should not be approved. SCE will define this term in the advice letter SCE Files to implement the 2018 GRC decision.[1366]

[1363] *See* Exhibit SCE-09, Vol. 1, Chapter IV.
[1364] *See* Exhibit SCE-25, Vol. 1, p. 6, lines 15-16.
[1365] *Id.* pp. 6-7.
[1366] *Id.* p. 7, lines 9-14.

11.3. Modification of the Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA)

ORA asks that the Commission reject SCE's proposal to modify the PLDPBA.[1367] TURN proposes that the Commission only continue the balancing account for pole replacement activities through the Pole Loading Program (PLP) and the deteriorated pole program if the Commission makes the account a one-way balancing account, with the limit for spending set at the authorized amount.[1368]

Both parties are incorrect. SCE has shown how uncertainties exist in both directions (overspend or underspend); thus, a two-way balancing account is justified.[1369] SCE has also shown that imposing a one-way balancing account would not actually encourage cost efficiency.[1370] Section 4.9 of this Opening Brief addresses pole-related spending and cost issues in greater detail.

11.4. Modification of the Safety and Reliability Investment Incentive Mechanism (SRIIM)

CUE proposes certain changes to SRIIM, and SCE has addressed those suggestions in its rebuttal.[1371] The Commission should adopt SCE's proposal as modified in its rebuttal.

11.5. ORA's Proposal To Establish a One-Way Storms Balancing Account

SCE has shown why ORA's proposal is not warranted. Storms are inherently unpredictable. A one-way balancing account would unfairly penalize shareholders for acts of nature that are outside of SCE's control.[1372] Precisely because of this volatility, the Commission has long accepted five-year averages for storm forecasts.[1373] Moreover, in SCE's 2015 rate case, ORA made the same proposal for a one-way storms balancing account. The Commission rejected it, finding that ORA's arguments "have no merit."[1374]

SCE has also addressed ORA's proposed reduction to the forecast of Account 598.170.[1375]

[1367] Exhibit ORA-10, p. 17.
[1368] Exhibit TURN-12, pp. 37-38.
[1369] Exhibit SCE-25, Vol. 1, p. 9, lines 5-13.
[1370] *Id*. at p. 9, lines 14-25.
[1371] *See* Exhibit SCE-18, Vol. 1, pp. 9-10.
[1372] Exhibit SCE-25, Vol. 1, p. 20, lines 3-4.
[1373] *Id*. at p. 20, lines 4-6.
[1374] *Id*. at p. 20, lines 6-10.
[1375] Exhibit SCE-18, Vol. 5, pp. 3-4.

11.6. ORA's Recommendation to Establish a Grid Modernization Memorandum Account

ORA suggests that Grid Modernization projects be denied on a blanket basis. ORA asks that, if the Commission were to approve any Grid Modernization projects, they should be subject to a memorandum account.

SCE's detailed rebuttal addressing Grid Modernization is found in Exhibit SCE-18, Vol. 10. SCE witnesses Brandon Tolentino and Jeff Gooding also provided extensive oral testimony at the evidentiary hearings.[1376] The majority of SCE's Grid Modernization efforts are driven by safety and reliability concerns, and are needed regardless of additional DER integration.[1377] Accordingly, these capital expenditures do not need to wait for the outcome of other ongoing proceedings such as the Distributed Resources Plan Proceeding. A memorandum account as ORA suggests is not merited.[1378]

11.7. ORTA's Recommendation to Establish a DER Memorandum Account

SCE provides detailed testimony in Exhibit SCE-18, Volume 10 addressing ORA (and TURN's) recommendations for the DER deferral pilot projects.[1379]

11.8. ORA's Recommendation to Establish a CS Re-Platform Memorandum Account

SCE explained in detail why SCE's CS Re-Platform O&M estimates are reasonable and consistent with best practices.[1380] But, if the Commission opts not to include these costs in the GRC, then a balancing account (rather than a memorandum account) should be authorized. The balancing account should: (1) cap recovery at $52.3 million, (2) allow year-end transfers to BRRBA for cost recovery, and (3) provide for annual review in ERRA Review proceedings.[1381]

11.9. CALSLA's Recommendation to Establish a Balancing Account to Record Tax Losses and Profits from Street Light Sales

In Exhibit SCE-26, SCE rebuts in detail CALSLA's suggestion to establish this balancing account. CALSLA's proposed balancing account should be rejected by the Commission.[1382]

[1376] SCE, Tolentino Tr.11 and SCE, Gooding, Tr. 13.
[1377] *See*, e.g., Exhibit SCE-25, Vol. 1, p. 21, lines 5-9.
[1378] *Id*. at p. 21, lines 14-16.
[1379] *Id*. at pp. 21-22.
[1380] Exhibit SCE-20, Vol. 2.
[1381] Exhibit SCE-25, Vol. 1, pp. 22-23.
[1382] *Id.* at p. 23, lines 26-28.

SCE has also addressed potential removal of assets from the GRC related to street light sales.[1383] In Update testimony to be submitted later in this GRC, SCE will remove from rate base all street light assets that have been included in a section 851 Application or Advice Letter so long as: (a) the Commission has approved the Application or Advice Letter, and (b) ownership and responsibility of the asset(s) has entirely transitioned from SCE to the purchaser.[1384]

12. JURISDICTIONAL ISSUES

13. SALES AND CUSTOMER FORECAST

To forecast SCE residential customer new meter connections, SCE uses a regression model that depends on the strong fundamental driver of housing starts.[1385] SCE specifies a polynomial distributed lag (PDL) term in its regression model to properly account for the time lag between housing starts and residential customer new meter connections. For its non-residential meter forecast model, SCE also utilizes fundamental economic drivers, such as non-farm employment, as well as relying on strong input of the residential meter forecast with a lagged result.[1386]

TURN, ORA, and the Consumer Federation of California (CFC) each propose modifications to SCE's meter forecasts to lower the forecast results. While each intervenor takes a different approach, a common theme is apparent: each unmoors its forecasts from the fundamental economic driver of housing starts or any other independent explanatory variable in favor of making arbitrary tweaks to SCE's model assumptions to lower SCE's new meter forecasts. As SCE explains, each of these "ends justify the means" approaches lacks basis. Favoring outcomes over principles in forecasting, however tempting, should be avoided.

13.1. CFC's Modifications to SCE's Commercial Meter Forecast Lacks a Principled Basis

CFC criticizes SCE's forecast of commercial and industrial (C&I) meters as featuring "a much higher meter/customer ratio than historical installations."[1387] SCE has provided a clear explanation for

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[1383] *Id*. at p. 24, lines 1-15.
[1384] *Id.*
[1385] *See* Exhibit SCE-115, p. 5 ("Historically, housing starts are strongly correlated with residential meter connections: On average, from 1998 through 2012, 84% of actual housing starts yielded new SCE meter connections.").
[1386] *See* Exhibit SCE-25, Vol. 1, p. 31, lines 15-16.
[1387] *See* Exhibit CFC-02, p. 5. (emphasis added).

why there may not be a one-to-one correlation between new meters and customer additions.[1388] SCE has also demonstrated that SCE's C&I meter forecast, in fact, features a lower meter/customer ratio than historical installations and CFC acknowledged this.[1389] In fact, SCE's forecast levels show close to a one-to-one correlation between new meters and customer additions.[1390]

CFC provides an alternative C&I meter forecast. CFC states, up front, that its forecast is akin to an autoregressive integrated moving average (ARIMA) model and that it relies heavily on a base year of 2008.[1391] SCE explained in its 2015 GRC why ARIMA is not appropriate for long-term (more than three months) forecasting, especially when there is a strong predictive variable.[1392] In its decision in SCE's 2015 GRC, the CPUC rejected ORA's ARIMA model in favor of SCE's PDL approach.[1393]

CFC also selects 2008 as its base year[1394] – the year that most heavily influences the forecast results. CFC acknowledges that 2008 was a year characterized by an extreme economic downturn.[1395] CFC also acknowledges that this modeling approach did not perform well for 2007,[1396] which is indicative of an unstable model. CFC also acknowledges a clear, slightly-lagged correlation between residential customers and C&I meters, but only recommends adjusting SCE's C&I meter forecast,[1397] further suggesting that CFC's approach lacks a principled basis.

13.2. ORA's Lag Specification is Unsupported

ORA's recommended new meter forecasts are lower for Test Year 2018 compared to SCE's. ORA's total number of new meter connections forecast is 2,480 (1,790 for residential and 690 for non-residential) fewer than SCE's projection.[1398] ORA's model not only significantly under forecasts SCE's new residential meters in 2016 but also performs worse than SCE's model.[1399] ORA's underperformance for 2016 is largely driven by its specification of a 36-month PDL (lag) for residential housing starts. In

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[1388] *See* Exhibit CFC-02, p. 8, Attachment 1 (CFC-SCE-001 Q.4.b), CFC, Roberts, Tr. 19/2760-2761.
[1389] *See* CFC, Roberts, Tr. 19/2769-1771; *see also* Exhibit SCE-114.
[1390] *See* Exhibit SCE-113; CFC, Roberts, Tr. 19/2761-2763.
[1391] *See* Exhibit CFC-02, p. 6 lines 13-17; CFC, Roberts, Tr. 19/2764 lines 10-18.
[1392] *See* Exhibit SCE-115, pp. 4-5; CFC, Roberts, Tr. 19/2766-2767.
[1393] *See* Exhibit SCE-116, D.15-11-021 Decision on Test Year 2015 General Rate Case for Southern California Edison Company, pp. 377-378 (November 5, 2015); CFC, Roberts, Tr. 19/2766-2767.
[1394] *See* Exhibit CFC-02, p. 5 lines 15-20; CFC, Roberts, Tr. 19/2768-2769.
[1395] *See* CFC, Roberts, Tr. 19/2769 lines 5-8.
[1396] *See* CFC, Roberts, Tr. 19/2769.
[1397] *See* CFC, Roberts, Tr. 19/2769 line 19-2771 line 4.
[1398] *See* Exhibit ORA-03, p. 1-2.
[1399] *See* Exhibit SCE-25, Vol. 1, p. 26 (discussion and Table III-6).

other words, ORA assumed that it takes three years from the start of home construction to the meter connection date. ORA therefore used housing starts data from 2013 to forecast new meter connections in 2016. In so doing, ORA captured housing market conditions in SCE's service territory at a low point and at an early stage of recovery following the Great Recession. This 36-month lag specification therefore suppressed ORA's new meter forecast for 2016. Incorporating actual 2016 meter data will produce a more realistic forecast for the rest of the forecast period.

ORA's use of a 36-month lag has no economic basis. Census data confirms that housing completions (a proxy for meter installations) lag behind housing starts from between 6 to 9 months for residential customers to 8 to 15 months for multifamily units.[1400] SCE specified a lag of up-to-18 months, with the largest impact centered around 9 months.[1401] ORA cited changes in weather as its justification for doubling SCE's lag period.[1402] While SCE sees no reason why weather events would create such an extreme result, the housing start data upon which SCE relies is seasonally adjusted, obviating the need for further adjustment.[1403] As with CFC, ORA's lag specification seems designed to achieve a desired outcome rather than to generate a stable model.

SCE has shown why ORA's C&I model inappropriately relies on ARIMA terms and should therefore be rejected.[1404]

13.3. TURN's Selective Reliance on Moody's Data Lacks a Principled Basis

TURN did not conduct its own modeling effort but instead sent SCE three sets of hypothetical or artificial housing starts data series to run in its model, modifying the housing starts assumptions in several ways.[1405] Without a strong or clear reason, TURN then subjectively selected one set of the obtained results from SCE among the three different outcomes as its recommended alternative forecast. TURN's recommendation is based purely on its subjective goal of creating a lower meter forecast. TURN's approach is not based on sound economic principles and should be rejected.

[1400] *See* Exhibit SCE-25, Vol. 1, Appendix F. *See also* ORA-SCE-227-MRK Q.02.
[1401] *Id.*
[1402] *See* Exhibit ORA-24 (SCE-ORA-031, SCE's Question, quoting SCE-ORA-002 Q.1).
[1403] *See* Exhibit SCE-56 (Question 5).
[1404] *See* Exhibit SCE-25, Vol. 1, p. 28, lines 1-16.
[1405] *See* TURN, Borden, Tr. 21 (Redacted), p. 2954, line 26 – 2955 lines 1-10.

First, TURN relies on actual housing start data from 2014-2016 to forecast 2017[1406] rather than relying on Moody's Analytics (Moody's) housing starts forecast. SCE has shown why this approach is problematic.[1407] TURN's reliance on the recent past (2014-2016) to forecast 2017 is akin to an ARIMA model, which, as already discussed, is inappropriate when forecasting long-term (*i.e.*, beyond three months), when better independent variables such as housing starts are available.[1408]

Next, TURN relies on Moody's growth forecast for the 2018-2020 period. SCE shows why this approach is also problematic.[1409] The purpose of TURN's adjustments, is, by TURN's own admission, to lower SCE's new meter forecast.[1410] TURN's changes to SCE's model amount to an exercise in cherry-picking[1411] – TURN uses Moody's housing start growth data for only certain years (2018-2020), while ignoring it for other periods (2017). Selectively relying on Moody's housing starts data in certain years, and not in others, is unprincipled and should be rejected.

TURN does not recommend any adjustments to SCE's customer additions forecast even though that forecast also relies on Moody's housing start data. While SCE stands by its customer additions forecast and is not suggesting it needs to be adjusted, this is further evidence of TURN's inconsistent and unprincipled approach. The overall result of TURN's adjustments is a lower new meter forecast that is presented as a legitimate forecast "based on" actual housing starts data.[1412]

In contrast, SCE consistently relies on Moody's, a reputable economic forecasting company unaffiliated with SCE, as a source of unbiased economic forecasts. SCE's approach of relying on unaffiliated, third-party economic vendors with no interest in the outcome of SCE's case is sound. SCE has provided examples of other utilities and regulatory bodies relying on such vendors.[1413] Forecasts from economic vendors are based on past economic and demographic history and incorporate assumptions about future economic and demographic trends that are periodically adjusted to account for new data. Despite the limitations and uncertainties inherent to any forecast, the Moody's housing starts

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[1406] Exhibit TURN-11, p. 31.
[1407] *See* TURN, Borden, Tr. 21 (Confidential), p. 2965, line 19 – 2966, line 11.
[1408] *See* Exhibit SCE-115, pp. 4-5; Exhibit SCE-116, excerpt from D.15-11-021 Decision on Test Year 2015 General Rate Case for Southern California Edison Company, pp. 377-378 (November 5, 2015).
[1409] *See* TURN, Borden, Tr. 21 (Confidential), p. 2966, lines 12 – 23.
[1410] *See* TURN, Borden, Tr. 21 Confidential/2967, lines 12-17.
[1411] *See* SCE, Sheng, Tr. 15/2092, line 15-16.
[1412] *See* TURN, Borden, Tr. 21 Confidential/2969, lines 8-26.
[1413] *See* Exhibit SCE-115 (Exhibit SCE-66 from 2015 GRC) p. 11; *See* SCE-25 Vol. 1, p. 30, fn. 60.

forecast still provides a sounder basis for meter connections forecasts than an arbitrary projection with no economic or demographic foundation.

In its prepared testimony, TURN justifies its arbitrary approach by pointing to SCE's track record of over-forecasting by reliance on housing starts data and suggests as much through presentation of TURN Figure 6, which compares SCE's and TURN's forecast costs for 2012 with actual costs.[1414] But in presenting this Figure, TURN leaves out some important facts. First, SCE has made changes to its model assumptions to avoid over-forecasting to the extent possible while still relying on a principled forecasting approach. In particular, SCE opted to use Moody's housing starts forecast only, rather than averaging the forecasts of both Moody's and IHS Global Insight[1415] as it had in 2012, primarily because IHS Global Insight's forecast produced an overly optimistic housing recovery. Second, TURN serves its prepared testimony in each rate case nearly one year later than SCE, so it is able to rely on an entire year more of actual data than SCE. TURN has used this approach in prior rate cases, including in SCE's 2012 rate case, upon which TURN relied to develop Figure 6. While SCE does not object to reliance on more recent data, such reliance does not make TURN a better forecaster; it simply makes TURN a later forecaster. Third, Figure 6 addresses costs, not new meter connections, and TURN acknowledged in hearings that those costs rely on more than just the new meter forecast.[1416]

Finally, TURN twice suggests that SCE has a motive to over-forecast, stating that SCE "earned excess profit for no ratepayer benefit,"[1417] but, when asked at hearings whether TURN had any evidence to support this statement, Mr. Borden admitted that he had none.[1418] For all of these reasons, TURN's proposed changes to SCE's new meter forecasts should be rejected.

14. OTHER OPERATING REVENUE

15. COST ESCALATION

SCE's proposed cost escalation methodology is the same as what the Commission authorized without changes in SCE's 2009, 2012 and 2015 GRCs.[1419] ORA adopts SCE's labor, non-labor, and

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[1414] *See* Exhibit TURN-11, p. 26.
[1415] *See* Exhibit SCE-25, Vol. 1, p. 30, lines 3-7.
[1416] *See* TURN, Borden, Vol. 21 Redacted/2957-2958.
[1417] *See* Exhibit TURN-11, p. 25, lines 10-11 and p. 28 lines 12-13.
[1418] *See* TURN, Borden, Vol. 21 Redacted/2960 lines 17-21.
[1419] Exhibit SCE 25, Vol. 1, page 33, lines 15-16 *citing* D.09-030-25, Cost Escalation, p. 314, D.12-11-051, Cost Escalation, p. 598, and D.15-11-021, Cost Escalation p. 546.

capital cost escalation methodologies, but relies on a more recent IHS Global Insight forecast.[1420] No party contests SCE's cost escalation methodology or escalation rates in this proceeding. ORA and SCE agree that SCE should update the labor, non-labor, and capital-related escalation rates using the most recent information available at the time of the update hearings. The Commission should accept SCE's cost escalation proposal.

16. POST-TEST YEAR RATEMAKING

SCE's proposed Post-Test Year Ratemaking Mechanism provides for increases in SCE's authorized revenue requirement in years 2019 and 2020 (sometimes referred to as the attrition years). The primary features of SCE's proposal include: (1) O&M escalation using the escalation rate methodology for cost escalation up to the test year, updated at the time of the advice letter filing that provides notice of the revenue requirement change for the following year;[1421] (2) capital-related cost increases using SCE's Board-approved capital budget, updated for changes in SCE's authorized cost of capital, including a mechanism to refund any unspent capital in 2018-2019 to ratepayers;[1422] and (3) a mechanism to address major exogenous changes in SCE's costs.[1423] The goal of SCE's post-test year ratemaking mechanism is to allow SCE to continue to provide adequate service to its customers in the attrition years, and to give SCE a reasonable opportunity to recover its costs and earn a reasonable return for its investors.

The post-test year mechanism that this Commission approves will have significant implications for SCE's ability to continue to provide service to its customers in the attrition years at the level approved by the Commission in the test year.[1424] This is particularly true because test year capital additions are not fully reflected in rates until the post-test year period.[1425] The Commission has adopted an attrition or post-test year increase for SCE since 1981.[1426] The Commission should continue to do so

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[1420] Exhibit SCE 25, Vol. 1, page 33, lines 6-7 *citing* ORA-4, p. 9 lines 19-20, p. 12 lines 2-3, p. 13 lines 5-6, p. 14 lines 1-2.
[1421] SCE-09, Vol. 1, pp. 117-120.
[1422] SCE-09, Vol. 1, pp. 117, 120-122.
[1423] SCE-09, Vol. 1, pp. 117, 122-123.
[1424] SCE-25, Vol. 1, p. 36.
[1425] SCE-09, Vol. 1, pp. 125-127.
[1426] SCE-25, Vol. 1, pp. 39-40 (responding to ORA's claim that utilities are not automatically entitled to attrition rate increases).

to help yield sufficient revenues for SCE so that the utility has a reasonable opportunity to earn its authorized rate of return in 2019 and 2020.[1427]

16.1. SCE's O&M Escalation Methodology

SCE's proposed post-test year mechanism escalates O&M expense using the same price indexes that SCE uses to escalate its O&M expense from the recorded year 2015 to the test year 2018.[1428] This part of SCE's mechanism was adopted for SCE's post-test year mechanism after the test years 2003, 2006, 2012, and 2015.[1429] ORA's cost escalation witness adopted this approach, and no party has challenged this approach in the proceeding.[1430] Notwithstanding acceptance of or lack of objection to SCE's escalation indexes to determine the test year revenue requirement, ORA and TURN suggest alternatives for the post-test year period. (CFC and SBUA do not specifically address O&M escalation rates, as they propose more generic alternatives for post-test year revenue adjustments.) These alternatives should be rejected by the Commission, as discussed below.

16.2. SCE's Proposed Capital Cost Increases

SCE's proposed post-test year mechanism includes capital costs associated with a budget-based forecast of capital additions. The associated revenue requirements are subject to refund if SCE's capital spending budgets are not fully implemented. Relying on SCE's projected capital additions is the most accurate way to project our capital requirements during the post-test year period.[1431] Moreover, it is consistent with cost of service ratemaking, and no party has argued to the contrary.

However, SCE also provides an alternate proposal for capital additions, which is to escalate SCE's test year capital additions by five percent in both 2019 and 2020, plus an adjustment for one project, the Customer Service Re-Platform capitalized software project.[1432] The five percent escalation rate is roughly double the escalation that results from projected changes in capital-good prices. However, the additional escalation is a reasonable "down payment" on the capital additions required to

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[1427] SCE-25, Vol. 1, p. 41.
[1428] SCE-09, Vol. 1, pp. 117-118.
[1429] SCE-25, Vol. 1, p. 42, Table V-9 (detailing structure of SCE's PTYR mechanisms since the 2003 GRC).
[1430] ORA-04, pp. 9, 12-14.
[1431] SCE-09, Vol. 1, pp. 117, 120-121.
[1432] SCE-09, Vol. 1, pp. 121-122.

build the next-generation grid that the Commission and other policymakers want and California needs.[1433]

16.3. ORA and Intervenor Proposals

ORA and several of the other intervenors in this case (TURN, CFC, and SBUA) propose post-test year ratemaking mechanisms that are inconsistent with cost-of-service ratemaking. These suggested mechanisms would result in O&M, capital additions, and revenue requirements that fall hundreds of millions of dollars below the reasonable amounts proposed by SCE. Adoption of these proposals or variants of them would jeopardize SCE's ability to provide expected levels of customer service and system improvements.[1434]

16.3.1. ORA

ORA's proposed mechanism for 2019 and 2020 is similar in form to SCE's proposal, but differs in some key respects. With respect to O&M escalation, ORA agrees with SCE's proposed O&M escalation methodology, but disagrees with SCE's proposal to update escalation rates.[1435] ORA also disagrees with SCE's proposed medical escalation rates.[1436]

For capital, ORA proposes increases in capital additions of 2.4% for 2019 and 2.8% for 2020, based on forecast increases in the Consumer Price Index.[1437]

ORA proposes that the post-test year mechanism extend for another year, through 2021. For 2021, ORA would simply increase SCE's revenue requirement by 2.7%, based on a forecast increase in the Consumer Price Index (CPI).[1438]

16.4. CPI-Based Mechanisms Should Not Be Used

ORA uses the CPI to calibrate the revenue requirement increase when proposing that post-test year ratemaking span an additional year.[1439] TURN bases O&M escalation in its proposed mechanisms

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[1433] *Id*.

[1434] SCE-25, Vol. 1, p. 37, Table V-8 (comparing revenue requirements and capital additions and expenditures based on SCE, ORA, and TURN proposals). CFC and SBUA proposals are not included in this table. However their proposals are addressed in other sections of this brief.)

[1435] ORA-21, p. 11.

[1436] ORA-21, pp. 10-11. This issue is addressed in section 8.2.5 of this brief.

[1437] ORA-21, p. 12.

[1438] ORA-21, pp. 13-14.

[1439] ORA-21, p. 13, line 27 through p. 14, line 3.

on the CPI.[1440] As explained in SCE's direct testimony on cost escalation, the CPI is not an appropriate index to use for escalating O&M costs or for escalating capital costs.[1441]

More broadly, general measures of inflation, such as the CPI, do not adequately track utility cost increases because they:

- Do not reflect the same basket of labor, materials, and capital inputs used to provide electricity service and their respective changes in input prices;
- Do not reflect the increases in capital expenditures projected by SCE; and
- Are not consistent with traditional regulated utility capital cost accounting procedures.[1442]

The CPI should not be used in a post-test year ratemaking mechanism when utility-specific indexes are available and provide *more accurate* estimates of utility cost changes. The CPI represents changes in the prices paid for goods and services that an average consumer purchases at home. The CPI does not include large categories of goods purchased by SCE, such as transformers, circuits, switches, towers, and poles. It cannot be used to escalate such costs.[1443]

The CPI is particularly deficient in tracking capital-related cost increases.[1444]

The Commission has noted the CPI's shortcomings more than once. In D.04-07-022, the Commission recognized that, although the CPI may be simple and accessible, those features did not make it appropriate as a measure of price changes faced by an electric utility.[1445] In a more recent decision, the Commission found that using a single index such as the CPI "fails to adequately capture the distinctions between expense and capital expenditure attrition."[1446] This criticism applies directly to ORA's proposal to establish a third post-test year, escalating SCE's revenue requirement by the CPI.[1447]

[1440] TURN-08, p. 12, line 14 through p. 13, line 7.
[1441] SCE-09, Vol. 1, p. 86, line 1 through p. 89, line 4.
[1442] SCE-25, Vol. 1, p. 43.
[1443] SCE-25, Vol. 1, pp. 43-44.
[1444] SCE-25, Vol. 1, p. 54 and Appendix G.
[1445] D.04-07-022, p. 278, as cited at SCE-25, Vol. 1, p.44.
[1446] D.14-08-032, p. 653, as cited at SCE-25, Vol. 1, p. 45.
[1447] SCE-25, Vol. 1, p. 45.

16.5. TURN, CFC, and SBUA

TURN recommends a two-part mechanism that escalates O&M expenses using the CPI or the CPI plus an adjustment. TURN bases capital-related attrition on a forecast of attrition-year plant using a historical average method.[1448]

CFC proposes that rate increases should be limited to recorded median income growth in the SCE service area. CFC estimates this increase at 2.3% per year, based on data from 1995 through 2014.[1449]

SBUA proposes 3% rate increase for 2019 and 2020.[1450] SBUA's testimony appears to use the terms "rate" and "revenue requirement" interchangeably. For purposes of this section, we assume that SBUA meant to use "revenue requirement."

16.6. TURN's Arguments About Incentives Are Incorrect

TURN argues that a broad-based price index provides better incentives for SCE to manage its costs during the post-test year period.[1451] This is simply not true. In the first place, even SCE's proposed post-test year mechanism does not precisely compensate SCE for changes in its expenses between test years.[1452] With respect to O&M costs, whether a broad-based index provides an appropriate incentive depends on whether or not the broad-based index increases more or less rapidly than the indexes that SCE has proposed to use.[1453]

In a related argument, TURN suggests that "[c]omparing the utility to itself or to similarly situated businesses reduces the pressure on the utility to stretch its performance."[1454] TURN provides no evidence that this true in any meaningful way.[1455] More importantly, the Commission recognized long ago that utility performance is not measured solely by cost control but also by provision of service to customers.[1456] Because SCE must provide safe and reliable service to its customers, it is reasonable to calibrate SCE's post-test year mechanism on indexes that are related to other utility businesses with

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[1448] TURN-08, pp. 12-14.
[1449] CFC-01, p. 1, 14.
[1450] SBUA-Brown Testimony, pp. 6, 41-42.
[1451] TURN-08, pp. 5-6.
[1452] SCE-25, Vol. 1, pp. 45-46. SCE-09, Vol. 1, p. 116.
[1453] SCE-25, Vol. 1, p. 46.
[1454] TURN-08, p. 5.
[1455] SCE-25, Vol. 1, p. 46.
[1456] SCE-25, Vol. 1, pp. 46-47.

similar obligations to serve. SCE's post-test year mechanism should not be calibrated to data taken from businesses that do not have similar obligations.[1457]

16.7. TURN's Seven-Year Attrition Methodology for Capital Additions Should Not Be Used

According to TURN's own testimony, TURN's method for determining capital expenditures would reduce SCE's capital expenditures by $879 million in 2019 and $620 million in 2020.[1458] These are substantial reductions. Although the Commission has not always adopted SCE's capital budget approach to capital additions in the post-test year period, the capital budget demonstrates that adopting TURN's method will result in substantial cuts from the programs outlined in the budget and will reduce SCE's ability to meet the needs of its customers during the post-test year period and after.[1459]

TURN attempts to support its proposal by an analysis graphing "net additions" as a percentage of total plant in service.[1460] However, SCE's analysis of TURN's data shows that TURN's capital additions method does an extremely poor job of explaining year-to-year changes in SCE's capital additions.[1461]

In addition, capital expenditures and capital additions are not the same. TURN's proposed mechanism is based on capital expenditures, not capital additions.[1462] Capital additions equal capital expenditures (including corporate overheads) minus contributions in aid of construction minus cost of removal (if any) plus allowance for funds used during construction.[1463] Contributions in aid of construction, cost of removal, and allowance for funds used during construction are not linear functions of capital expenditures.[1464] Therefore, even if TURN's analysis of capital additions did a good job of explaining year-to-year changes in capital additions, there is no guarantee that its results would be applicable to capital expenditures.

[1457] SCE-25, Vol. 1, p. 47.
[1458] TURN-08, p. 16.
[1459] SCE-25, Vol. 1, p. 49.
[1460] TURN-08, p. 7, Figure 1.
[1461] SCE-25, Vol. 1, pp. 49-51.
[1462] TURN-08, p. 14.
[1463] SCE-09, Vol. 2, pp. 5-10. Although Figure 1 on p. 6 is a diagram of SCE's capital addition forecasting process, it mirrors the actual work order closing process.
[1464] Contributions in aid of construction and cost of removal can differ greatly between two projects of similar capital expenditures. Allowance for funds used during construction is a function of the time that it takes to build a project, so it can also differ greatly between two projects of similar capital expenditures.

16.8. Growth in Median Income Is Not an Appropriate Metric

As noted above, CFC proposes that rate increases should be limited to recorded median income growth in the SCE service area. CFC estimates this increase at 2.3% per year, based on data from 1995 through 2014.[1465]

This is not how California utility regulation works. In 1993, the Commission wrote the following description of the "regulatory compact":

> Building on the compact's legal and economic foundations, the actions of this Commission, California's Legislature, the courts, state and federal agencies, and Congress have combined to form four oft-cited elements of what has come to be referred to as the "traditional regulatory compact." Under that compact an investor-owned public utility in California was granted 1) an exclusive retail franchise to serve a specific geographic region; 2) an opportunity to recover prudently incurred expenses; 3) an opportunity to earn a reasonable return on investment; and 4) powers of eminent domain. In return for these privileges, the utility was subject to cost and price regulation by the Commission, and *required to provide safe and reliable service to all customers in its service area on a nondiscriminatory basis*. This latter feature of the compact is commonly called the utility's "duty," or "obligation" to serve.
>
> The Commission fulfills its obligations under the compact through a decision making process which attempts to *balance the interest of current and future consumers and the financial interest of the utility accepting the duty to serve*.[1466]

This commentary says nothing about limiting rate increases to the growth of median income in a prior period, or to any other extraneous index. Indeed, while the Commission pronouncement talks about a balance between the interests of customers and the financial interest of the utility, that balance includes future customers who will need a safe and reliable utility system when they begin taking service from the utility.

In fact, CFC discusses infrastructure replacement needs as follows: "Most utilities in the country are facing significant, unavoidable infrastructure needs…Thus, SCE's proposed revenue requirement is

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[1465] CFC-01, pp. 1, 14.

[1466] Division of Strategic Planning, California Public Utilities Commission, "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future," February 1993. *Available at* http://docs.cpuc.ca.gov/published/report/3822.htm and http://docs.cpuc.ca.gov/word_pdf/REPORT/3822.pdf. (emphasis added; footnotes omitted). Cited at SCE-25, Vol. 1, p. 47.

reasonable in this context."[1467] SCE's proposal should be adopted to promote safety and reliability of SCE's system for present and future customers in the communities we serve.

16.9. SBUA's Proposal Is Faulty

SBUA proposes that SCE's revenue requirement be increased by three percent in 2019 and 2020.[1468] SBUA's only analysis supporting this recommendation is a reference to historical price inflation in the United States, as measured by the CPI for all items less food and energy.[1469] This variant of the CPI is not a valid measure of price inflation for the goods and services that SCE purchases.[1470] SBUA's proposal should be rejected.

16.10. ORA's Proposal to Extend Post-Year Ratemaking for a Third Year Should Be Rejected

ORA proposes to add an additional year to the post-test year mechanism and increase SCE's revenue requirement by the CPI in that year.[1471] This is an incorrect approach. As discussed in SCE's testimony, such a mechanism will fail to properly include the construction work in progress (CWIP) balance existing at the end of the second year of post-test year ratemaking.[1472] In responding to a data request from SCE, ORA admits that it had done no additional analysis beyond the discussion in ORA-21, which simply notes that ORA has proposed this idea before and gives an estimate of the revenue requirement change.[1473] Nowhere does ORA attempt to evaluate how well its proposal corresponds to the cost increases that SCE would experience in a third year of post-test year ratemaking.[1474] The Commission should decline this proposal, as it has done before.[1475]

16.11. Escalation Rate Updating Should Be Included

ORA appears to oppose SCE's proposal to update labor escalation rates.[1476] ORA claims that its position is consistent with the 2015 SCE GRC decision. But that is not the case. ORA appears to have

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[1467] CFC-01, p. 12.
[1468] SBUA-Brown Testimony, Recommendation 15.
[1469] SBUA-Brown Testimony, pp. 41-42, Exhibit 1.
[1470] SCE-25, Vol. 1, p. 55.
[1471] ORA-21, p. 13, line 21 through p. 14, line 3.
[1472] SCE-09, Vol. 1, pp. 125-127. SCE-25, Vol. 1, pp. 52-53.
[1473] SCE-25, Vol. 1, p. 53.
[1474] SCE-25, Vol. 1, p. 53.
[1475] *See* D.16-06-005. *See also* D.17-05-013, pp. 197-198 & OP 17 at p. 251.
[1476] ORA-21, p. 11, lines 23-24.

incorrectly read the specific language of the decision.[1477] Escalation rates should be updated so that the forecast escalation rates that are used for each annual advice letter are the most accurate ones available. SCE's proposal should be adopted.

16.12. Conclusion Regarding Post-Test Year Ratemaking

The Commission has adopted a post-test year ratemaking mechanism for SCE in every GRC extending back to the 2003 Test Year GRC.[1478] Before 2003, the Commission approved attrition mechanisms in GRCs extending back to 1981.[1479] These mechanisms have generally provided reasonable increases in SCE's base revenue requirement between GRC test years. SCE's proposed mechanism in this GRC will provide reasonable increases in SCE's revenue requirement for 2019 and 2020. SCE respectfully requests that the Commission approve it as proposed.

17. RATE BASE COMPONENTS

17.1. Electric Plant

SCE's forecast Electric Plant balances were presented in Exhibit SCE-09, Volume 2. As discussed in that exhibit, forecast Electric Plant is built by starting with 2015 recorded plant balances, then adding forecast plant additions.[1480] Plant additions are based on forecast capital expenditures, such as those for Generation, Transmission & Distribution, and Customer Service, which are addressed separately in the corresponding sections of this brief. Authorized 2018 Electric Plant will be computed through the Results of Operations model based on authorized capital expenditures and capital additions.

17.2. Depreciation Expense

Although Depreciation Expense is not a component of rate base, it accrues to accumulated depreciation, which is. As discussed in SCE's direct testimony, depreciation expense represents the periodic return of capital to utility investors.[1481] Authorized Depreciation Expense is a derived number, computed by applying the authorized depreciation rates to the corresponding authorized investment. SCE's and other parties' recommendations on depreciation rates are addressed in Section 19 of this

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[1477] SCE-25, Vol. 1, p. 56.
[1478] SCE-09, Vol. 1, pp. 123-124.
[1479] SCE-25, Vol. 1, pp. 39-40.
[1480] Exhibit SCE-09, Vol. 2, pp. 1-14.
[1481] Exhibit SCE-09, Volume 2, p. 17.

brief. Authorized 2018 Depreciation Expense will be calculated through the Results of Operations model based on the authorized depreciation rates and plant balances.

17.3. Taxes

SCE's forecast of test year state and federal regulatory tax expense – income taxes, payroll taxes, and property taxes – is presented in Exhibit SCE-09, Volume 2, pages 19-40. No party contests SCE's proposed method of computing test year regulatory tax expense. Authorized 2018 state and federal income tax expenses will be recomputed through the Results of Operations model based on authorized revenues, expenses, and capital expenditures. Authorized payroll tax expenses will also be recomputed based on authorized labor expenses using the uncontested approach discussed in Exhibit SCE-09, pages 34-36. Finally, authorized property taxes will be recomputed based on authorized plant balances applying the approach discussed in Exhibit SCE-09, pages 36-40.

17.4. Rate Base

SCE's forecast 2018 rate base is presented in Exhibit SCE-09, pages 41-86. Authorized 2018 rate base is the net of several separate line items, several of which are contested in this proceeding. SCE addresses those individual rate base line items below.

17.5. Customer Advances

As discussed in Exhibit SCE-09, Volume 2, Customer Advances represent refundable amounts provided by others to construct new distribution facilities to be served by the utility. Tariff Rule 15 requires property developers to advance construction costs that exceed the allowance set forth in that rule. Customer Advances are not interest-bearing and because developers, not utility investors, provide this zero-interest funding, utility investors earn no rate of return on Customer Advances (*i.e.*, they are subtracted from rate base).

SCE forecast Customer Advances based on a three-part analysis of: (1) estimated net advances for Electric Construction; (2) estimated refunds to customers; and (3) customer advances that will permanently offset rate base as a Contribution in Aid of Construction (CIAC).[1482]

The forecast for estimated net advances for Electric Construction is a two-part analysis that, first, estimates the level of future receipts (*i.e.*, new customer advances provided by developers) and, second,

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[1482] Exhibit SCE-09, Vol. 2, p. 44; Exhibit SCE-25, Vol. 2, p. 2.

estimates when SCE expects to refund the advances back to the developers. To forecast receipts of customer advances, SCE computed a five-year average (2011-2015) of advances per meter set ($555), then multiplied that average times forecast meter sets. Forecast refunds relied on a 10-year pattern of historical refunds to developers. The net amount of these two forecasts comprises SCE's balance of net advances for Electric Construction.[1483]

SCE forecast Customer Advances - Temporary Services as a five-year (2011-2015) average of recorded balances. CIAC are amounts not refunded to developers, so they represent a permanent reduction to rate base. As shown in Exhibit SCE-09, Volume 2, page 45, SCE forecasts decreasing CIAC balances due to lower cash advances from developers in the tenth year preceding the forecast year.

Both ORA and TURN challenge SCE's Customer Advances – Electric Construction. ORA challenges SCE' forecast of Customer Advances – Temporary Services. Those issues are discussed in the following sections. No party challenges SCE's CIAC forecast, which should be found reasonable.

17.5.1. Customer Advances – Electric Construction

Forecast Customer Advances – Electric Construction are driven by forecast meter sets. TURN proposes a different meter forecast than SCE. SCE addresses TURN's meter set forecast in Exhibit SCE-25, Volume 1, pages 1-7 and summarizes that evidence elsewhere in this brief. To the extent the Commission adopts a different meter forecast than SCE's, there will be a corresponding effect on authorized Customer Advances based on the methodology discussed in Exhibit SCE-09, pages 42-45 (See Exhibit SCE-25, Volume 2, p. 6).

In contrast to SCE's five-year average of advances per meter set, ORA performed a linear regression analysis of six years (2010-2015) of data with customer meter sets as the independent variable and customer advances as the dependent variable. ORA's regression resulted in an estimated $1,494 customer advance per meter set, higher than any recorded value in SCE's history, and yielded a $91.4 million forecast (net of refunds), a $19.1 million increase over SCE's $72.3 million.[1484] Because Customer Advances are a credit (reduction) to rate base, ORA's forecast would reduce SCE's 2018 authorized rate base by $19.1 million.

[1483] Exhibit SCE-09, Vol. 2, p. 44.
[1484] Exhibit SCE-29, p. 406.

In rebuttal, SCE presents an alternative regression analysis based upon ORA's methodology, but using ten years of data rather than ORA's six. Exhibit SCE-25, Volume 2 shows the ORA methodology using different sets of data included in workpapers (2006-2011; 2007-2012; 2008-2013; 2009-2014 and 2006- 2015) and the results of every alternative analysis using ORA's regression methodology corroborates the reasonableness of SCE's forecast,[1485] which should be adopted.

17.5.2. Customer Advances – Temporary Services

To forecast Customer Advances – Temporary Services, SCE averaged 2011-2015 recorded balances, then escalated that average by forecast non-labor escalation rates.[1486] Claiming the five-year average "put a spurious dip into [SCE's] forecast," ORA forecast this account by escalating the recorded 2015 balance.[1487]

In rebuttal, SCE points out that an average of upwardly trending data will always be lower than the most recent data point.[1488] But that fact does not render the average "spurious." In prior GRCs, ORA has asserted that averaging "covers a longer time period which includes periods of some economic growth, smooths the data, and takes into consideration that there is not absolute certainty that the economic conditions will be similar."[1489] ORA's claim that 2015 data represents a "spurious dip" is not supported by any analysis and ORA provides no reason for changing its prior averaging approach other than the result – a lower rate base forecast. SCE's forecast of Customer Advances – Temporary Services is reasonable, follows GRC precedent, and should be adopted.

17.6. Materials and Supplies

SCE maintains an inventory of Materials and Supplies (M&S) for new plant construction and operating and maintenance needs. SCE separately forecast M&S balances for Transmission & Distribution, Generation, and Information Technology. SCE forecast $226.965 of 2018 M&S. ORA challenges SCE's M&S forecasts for Generation and T&D.

[1485] Exhibit SCE-25, Vol. 2, p. 6.
[1486] *Id*. p. 7.
[1487] Exhibit ORA-20P, p. 10.
[1488] Exhibit SCE-25, Vol. 2, p. 7.
[1489] Exhibit SCE-25, Vol. 2, p. 7 (citing A.10-11-015, Exhibit DRA-19, pp. 4-5).

17.6.1. Generation M&S

For Generation M&S, SCE's forecast was based on recorded data excluding unpaid invoices for inventory maintained at the Palo Verde Nuclear Generating Station (PVNGS).[1490] In rebuttal, SCE shows that its PVNGS adjustment is appropriate. The lag in receipt of detailed accounting information from the operating agent of PVNGS causes a lag in recording that inventory, which causes SCE to forgo a return on the inventory until the month it is recorded. ORA's proposed adjustment for unpaid inventory is not appropriate,[1491] and SCE's forecast of Generation M&S should be adopted.

17.6.2. T&D M&S

Computing a three-year moving average, ORA proposes a $391,000 reduction to SCE's T&D M&S balance.[1492] In rebuttal, SCE shows that its analysis already incorporated a three-year average, rendering ORA's second averaging step unnecessary.[1493] SCE's forecast is reasonable and should be adopted.

17.7. Working Cash

ORA proposes a $6.9 million reduction to SCE's working cash forecast, claiming that the bank balances SCE maintains are not required under Standard Practice U-16, D.12-11-051, D.09-03-025, and D.06-05-016.[1494] SCE's rebuttal shows that, although these balances are not required by the banks, they are functionally required for operational purposes.[1495] However, SCE does not contest ORA's proposed adjustment.

17.8. Lead Lag Study

A lead-lag study identifies the timing difference between receipt of revenues and payment of expenses.[1496] For this GRC, SCE's analysis shows that, on average, SCE pays expenses 15.1 days before

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[1490] Exhibit SCE-29, p. 408.
[1491] Exhibit SCE-25, Volume 2, p. 8.
[1492] Exhibit SCE-25, Volume 2, p. 8, footnote 21, which cites to ORA's workpapers for the calculation of a three-year average.
[1493] Exhibit SCE-25, Volume 2, p. 8.
[1494] Exhibit ORA-20P, p. 17. *See* WP to Exhibit SCE-09, Vol. 2, Chap. IV, Book A, pp. 183-223, for a copy of Standard Practice U-16.
[1495] Exhibit SCE-25, Vol. 2, p. 9.
[1496] Exhibit SCE-09, Vol. 2, p. 61.

receiving revenues.[1497] The Lead Lag Study yields separate estimates of revenue lags and expenses lags, and the latter are further broken down into subcomponents for various expense categories. Most of the components of SCE's Lead Lag Study are not contested, but TURN and ORA propose several changes to individual components, which are discussed in the following sections.

17.8.1. Revenue Lag Days

"Revenue lag is the number of days from the time service is delivered to the time the customer payment is made available in SCE's bank account."[1498] SCE's Revenue Lag Day analysis followed the procedures set forth in the Commission's Standard Practice U-16.[1499] TURN proposed adjusting SCE's revenue lag days to account for Green House Gas revenue returned to customers consistent with D.15-11-021, and SCE agreed to TURN's proposal, reducing its estimated revenue lag by 0.94 days.[1500]

ORA's Revenue Lag Day testimony comprises a single sentence: "ORA is reducing SCE's requested Revenue Lag Days by 2.66 days to 43.29 to smooth out the fluctuations caused by SCE recalculating annual estimates every GRC." ORA does not identify any faults with SCE's analysis of 2015 recorded data. The only apparent rationale supporting ORA's position is that it would lower SCE's rate base. ORA provides no valid reason for the Commission to rely on amounts authorized in prior SCE GRCs.[1501] With the adjustment proposed by TURN discussed above, SCE's Revenue Lag Day estimate is reasonable and should be adopted.

17.8.2. Income Tax Lag

The Income Tax Lag is one component of the Expense Lag calculation and "represents the period from when the current tax expenses are accrued to the time they are due by statutory law."[1502] SCE's 2018 estimated Income Tax Lag day calculation is based on dates prescribed by California and Federal tax law.[1503] ORA's proposal "is based primarily on estimated tax payments recorded over an eight-year period (2008-2015)," a period during which SCE made no estimated tax payments half of those years, in part due to large bonus depreciation deductions that are set to expire during this rate

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[1497] Exhibit SCE-09, Vol. 2, p. 61.
[1498] Exhibit SCE-09, Vol. 2, p. 62.
[1499] Exhibit SCE-09, Vol. 2, p. 62.
[1500] Exhibit SCE-25, Vol. 2, p. 10.
[1501] *Id*. p. 11.
[1502] Exhibit SCE-09, p. 68.
[1503] *Id.* at pp. 69-70; Exhibit SCE-25, Volume 2, pp. 13-14.

cycle.[1504] ORA's Income Tax Lag Day calculations rely on data that is not representative of the future; SCE's proposal to base Income Tax Lag Days on statutory payment dates is reasonable.

17.8.3. Fuel and Purchased Power Expense Lag

Fuel and Purchased Power are two components of the overall Expense Lag calculation. Fuel costs represent the natural gas, diesel, propane and nuclear fuel amounts used by SCE generating stations.[1505] SCE calculated separate lag days for natural gas, diesel, and propane.[1506] Nuclear Fuel Lag was set at zero, while Nuclear Fuel – Other waste disposal was estimated to have an expense lag of 7.1 days.[1507]

Purchased Power expense lags were separately computed for: (1) Qualifying Facilities (QF) paid via United States Postal Service; (2) QFs paid via Electronic Funds Transfer; and, (3) Non-QF Bilateral and Firm agreements, Power Exchange, and other energy-related costs.[1508]

To compute both Fuel and Purchased Power expense lags, SCE relied on data from its Spring 2016 forecast. TURN proposes using the more recent Fall 2016 forecast to compute Fuel and Purchased Power expense lags.[1509]

To compute the Fuel expense day lag, ORA proposes using the more recent Fall 2016 forecast.[1510] However, ORA did not explicitly address SCE's Purchase Power expense lag forecast, so it is implicitly relying on SCE's initial Spring 2016 forecast.

In rebuttal testimony, SCE agreed with TURN that the Fall 2016 forecast provides a more reasonable basis for computing expense lags for both Fuel and Purchased Power.[1511] If ORA proposes retaining the Spring 2016 forecast to compute Purchased Power, that position would yield logically inconsistent results.

[1504] Exhibit SCE-25, Vol. 2, pp. 13-14.
[1505] Exhibit SCE-09, Vol. 2, p. 64.
[1506] *Id.*
[1507] *Id.* pp. 64-65.
[1508] *Id.,* p. 65
[1509] Exhibit SCE-25, Vol. 2, p. 16, citing TURN response to SCE data request SCE-TURN-004, Question 1(c).
[1510] Exhibit ORA-20P, p. 19. SCE also noted in its rebuttal an apparent computational error in ORA's testimony. Using the Fall 2016 forecast would yield a Fuel expense lag of $155.9 million, rather than the $156.2 million shown in ORA's testimony. Exhibit SCE-25, Vol. 2, p. 16.
[1511] Exhibit SCE-25, Vol. 2, p. 16.

Aside from addressing the TURN and ORA Fuel and Purchased Power expense lag days, SCE's rebuttal also identifies a reduction to its expense lag estimate. SCE's application separately estimated Purchased Power payments made via United States Postal Service (USPS) from those made by Electronic Funds Transfer (EFT). SCE's application assumed discontinuing USPS for these payments and relying solely on EFT. Based on more recent information, SCE now estimates making 31% of its Purchase Power payments via USPS. Because it takes more time for payments to clear when sent by USPS than by EFT, this changed assumption increases SCE's expense lag days. SCE identifies the revised expense day calculation in its rebuttal.[1512]

17.8.4. Other O&M Expense Lag

Other O&M Expense Lag represents "non-labor expenses associated with balancing accounts," and is intended "to compensate investors for the time between the recording of utility costs and payment of those costs."[1513] SCE's analysis showed 12.1 expense lag days for this category. ORA proposes increasing this to 43.9 days, based on a single sentence in its testimony, which claims: "SCE incorrectly categorized [Other O&M Expense] as Labor when it is a non-labor expense."[1514] ORA is correct in identifying this as a non-labor expense; that is how SCE categorized it, as stated in the sentence from SCE's direct testimony quoted above. ORA apparently confused this line item with that for SCE labor, which both coincidentally have 12.1 lag days.[1515] SCE's 12.1 expense lag days for Other O&M expense were computed correctly and should be adopted.

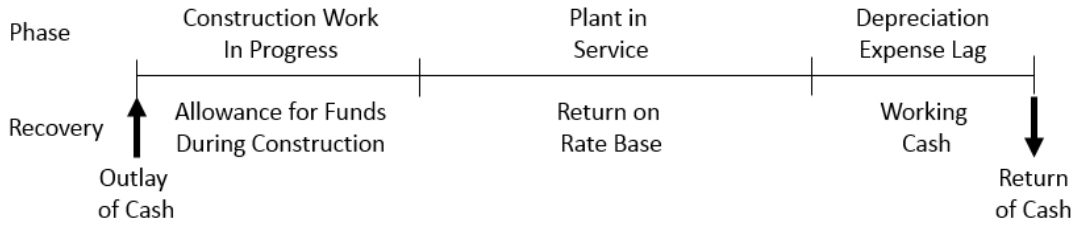
17.8.5. Depreciation & Deferred Income Tax Lag

SCE's Expense Lag Day calculation includes a provision for the difference between receipt of revenues and accrual of depreciation expense and deferred income taxes. TURN posits that "SCE should not collect cash working capital for non-cash items."[1516] TURN acknowledges depreciation and deferred taxes are recognized categories of working cash in Commission Standard Practice U-16, but asserts this practice "is another element of SP U-16 worth considering on the merits and substance of what it means for ratemaking today, rather than what was set as a ratemaking practice 50 years ago."[1517] TURN

[1512] *Id.* at p. 17.
[1513] Exhibit SCE-09, Vol. 2, p. 66.
[1514] Exhibit ORA-20P, p. 21.
[1515] Exhibit SCE-25, Vol. 2, p. 17.
[1516] Exhibit TURN-11, p. 44.
[1517] Exhibit TURN-11, p. 45.

provides no authority for the proposition that accounting for depreciation and deferred taxes has changed since Standard Practice U-16 was adopted. It was true then and remains true today that Depreciation and Deferred Income Taxes are accruals. This does not change the need to recognize these line items in the Expense Lag Day calculation.

SCE's rebuttal points out that, although these two items are both accrued, the other side of the accounting entry lowers the rate base on which the utility earns a rate of return.[1518] The utility reduces rate base at the midpoint of the service period during depreciation and deferred income taxes are accrued.[1519] But, on average, customers do not render payment until 46 days after the service is rendered, creating a lag between the date rate base is lowered and the revenues are received.[1520] TURN's proposal inappropriately cuts out the last leg of recovery.



It remains just as appropriate today to compensate investors for that lag as it was when Standard Practice U-16 was adopted.

Finally, the rate case of a single utility is not the forum to adopt such a significant change to Standard Practice U-16. If TURN believes this standard practice should be revised, TURN may petition the Commission for a rulemaking where it could advocate an industry-wide change. While SCE does not agree that such a change is appropriate, if a change is to be considered, it should be applied evenly to all affected utilities.

17.9. Customer Deposits

SCE makes primary and secondary recommendations regarding customer deposits in this proceeding. SCE's primary recommendation is to adjust SCE's revenue requirement downward, thereby treating customer deposits as debt that is available to finance rate base.[1521] SCE originally proposed

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[1518] Exhibit SCE-25, Vol. 2, p. 19.
[1519] Exhibit SCE-25, Vol. 2, p. 19.
[1520] *Id.*
[1521] SCE-09, Vol. 2, pp. 82-83; SCE-25, Vol. 2, p. 26.

implementing this revenue requirement reduction by reducing SCE's embedded cost of debt for this rate case.[1522] However, in rebuttal testimony, SCE accepted a calculation proposed by ORA. SCE revised its proposal to implement ORA's approach of multiplying the level of customer deposits by the difference between SCE's authorized cost of long-term debt and a projection of the short-term interest rate (90-day commercial paper rate).[1523]

17.9.1. Level of Customer Deposits

Although SCE agrees with ORA's method for incorporating customer deposits into SCE's GRC revenue requirement, the Commission should not incorporate ORA's specific components of the calculation.[1524] In particular, ORA provides a forecast of customer deposits based on only four data points (2012 through 2015), even though data on customer deposits is available on an annual basis for many years.[1525] Indeed, historical data over a nine-year period shows that the upward trend found in ORA's simple analysis is not indicative of how customer deposits have actually behaved over a longer term.[1526] From 2007 through 2015, SCE's customer deposits averaged $215.3 million. This is considerably less than the amount that SCE proposes to use in estimating SCE's revenue requirement reduction. SCE's suggested figure is $231.9 million before the 10% reduction discussed below.[1527]

The historical data for customer deposits does not show a consistent upward trend because the Commission's credit policies change from time to time. For example, the Commission changed its customer deposits policy in response to the Great Recession that began in 2008. The reduction in customer deposits between 2009 and 2012 shows that these funds can be affected by events beyond SCE's control and are not necessarily permanent.[1528]

17.9.2. The Commission Should Permit SCE to Continue Its Program of Using Customer Deposits to Support Minority and Community Banks

Beginning with its 2012 GRC, the Commission has granted SCE permission to use a portion (up to 10 percent) of its customer deposits to promote the Company's use of minority and community

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[1522] SCE-09, Vol. 2, pp. 82-83.
[1523] SCE-25, Vol. 2, p. 26.
[1524] *Id.*
[1525] *Id*. at p. 24.
[1526] *Id*. at pp. 24-25.
[1527] *Id*. at p. 25.
[1528] SCE-09, Vol. 2, p. 79.

banks.[1529] This policy was continued in SCE's 2015 GRC,[1530] and SCE proposes that it continue in this GRC.[1531] No Party opposes this proposal,[1532] and the Commission should adopt it.

17.9.3. Customer Deposits Should Not Be An Offset to Rate Base

TURN argues that SCE's rate base should be reduced by 90% of SCE's customer deposits (after supporting SCE's proposal to deposit up to 10% of customer deposits in minority and community banks).[1533] As discussed at length in SCE's testimony, TURN's proposal should be rejected for the following reasons:

- SCE's customer deposits are interest-bearing. SCE pays customers interest on their deposits and TURN's recommendation explicitly admits this by stating that "[t]he Commission should grant an offsetting interest expense …".[1534] As such, the Commission's Standard Practice manuals SP U-16 (issued in 1968) and SP U-16-W (issued in 2006) specify that interest-bearing deposits should not affect the calculation of working cash.[1535] (Working cash is a part of rate base; thus, rate base should not be reduced by the level of customer deposits.)
- Customer deposits are not like working cash adjustments such as vacation accruals.[1536] Customer deposits are clearly debt owed to customers. Offsetting rate base with customer deposits effectively treats them as partially as common equity, which they are not.[1537]
- Customer deposits are debt, not equity, and TURN's proposal, by treating them as debt, weakens SCE's credit quality.[1538] This increased financial risk is exacerbated by the Commission's reduction of rate base for fuel inventories.[1539] Despite the closure of San Onofre Nuclear Generating Station, SCE's fuel inventories remain sizable.[1540]

[1529] D.12-11-051, pp. 628-630, COL 534, p. 877.
[1530] D.15-11-021, p. 474, FOF 567, p. 533, COL 148, p. 550.
[1531] SCE-09, Vol. 2, pp. 83-84.
[1532] ORA's testimony appears to be silent on this issue, but the Joint Comparison Exhibit indicates that ORA does not oppose SCE's request. SCE-29, p. 259. TURN endorses the proposal. TURN-03, p. 41.
[1533] TURN-03, p. 41.
[1534] SCE-25, Vol. 2, p. 27, referencing TURN-03, p. 41.
[1535] SCE-09, Vol. 2, pp. 72-74.
[1536] *Id*. at pp. 77-79. SCE-25, Vol. 2, p. 28.
[1537] *Id*. at pp. 72-76, 80-81.
[1538] SCE-25, Vol. 2, pp. 29-30.
[1539] SCE-09, Vol. 2, pp. 81-82. SCE-25, Vol. 2, pp. 29-30. SCE does not seek any change to the treatment of fuel inventory in this proceedings.
[1540] SCE-25, Vol. 2, p. 31.

- Offsetting rate base by customer deposits provides an excess reward to customers.[1541]
- As noted above, customer deposits are not necessarily permanent.[1542]

SCE's proposal correctly recognizes that customer deposits are debt and accounts for them accordingly.

17.10. AFUDC

SCE's proposed AFUDC rates through the post-test year period are fully explained and supported[1543] and have not been opposed by any party. AFUDC is the standard way of capitalizing equity and debt costs incurred for financing Construction Work in Progress (CWIP). Capitalizing these costs helps ensure that full construction costs are paid by customers who received the services provided by the capital projects. It also helps ensure that investors' costs incurred during construction are fully recovered after the capital projects enter service. The Commission should adopt SCE's proposed AFUDC rates.

17.11. Rate Base Components – Additional Issues

17.11.1. Long-Term Incentives

ORA and TURN oppose customer funding of SCE's Long-Term Incentives. A corollary of SCE's requested recovery of Long-Term Incentive compensation is a $4.3 million credit (reduction) to forecast rate base to account for the timing difference between the receipt of cash from customers and the funding of the incentives.[1544] SCE addresses the proposed disallowance of Long-Term Incentives in Section 8.2.2. of this brief. If the Commission adopts the proposed disallowance, authorized rate base should be correspondingly increased by $4.3 million.

17.11.2. Other Accounts Receivable

SCE estimates 2018 Accounts Receivable rate base of $82 million. SCE's estimate is based on 2015 recorded data, the same approach followed in prior GRCs.[1545] After revising its original proposal, TURN recommends a $23.5 million reduction to SCE's forecast, which TURN attributes to using

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[1541] SCE-09, Vol. 2, pp. 80-81.
[1542] *Id.* at p. 79.
[1543] Exhibit SCE-09, Vol. 2, pp. 12-14, App. A.
[1544] Exhibit SCE-25, Vol. 2, p. 9.
[1545] Exhibit SCE-29, p. 409.

recorded 2016 data. Of course, 2016 data is of more recent vintage than 2015 data, but this does not mean it yields a more representative forecast of 2018 balances. For example, if SCE's authorized revenue requirement were lowered between 2015 and 2016, this would logically lead to a reduction in receivables. There is no evidence showing that the 2016 Accounts Receivable amount is any more representative of 2018 than SCE's estimate.

18. DEPRECIATION STUDY

Under cost-of-service ratemaking, depreciation expense allocates the costs of purchasing, installing, and removing capital assets. As a capital-intensive business, SCE's depreciation expense is necessarily a significant part of its overall annual revenue requirement. The objective of a proper depreciation study is to estimate the total remaining life of all assets surviving across SCE's service territory at the time of the study—from transmission towers, poles and wires, to hydro generation stations, to solar rooftop panels and beyond—and set depreciation rates that will allocate the original cost of the assets, plus their estimated cost of removal (also known as retirement), to the generation of customers who benefit from their service.[1546] Depreciation expense accrues in SCE's depreciation reserves until the assets are retired and removed.

The depreciation study SCE performed in this GRC was different in two significant respects from the 2015 GRC. First, consistent with the Commission's preference,[1547] SCE's service life proposals for T&D assets are based on the results of SCE's first ever actuarial analysis instead of on a simulated plant record (SPR) analysis. The study results led SCE to propose average service lives that are, on the whole, the same or longer than what the Commission approved in the 2015 GRC. (The longer the average service life of assets, the lower the depreciation expense, all other things equal). The vast majority of SCE's service life estimates are uncontested. Thus, the Commission need only resolve three open issues about estimated service lives—for one T&D plant account, a class of small hydro generation units, and solar photovoltaic rooftop panels.

Second, in response to the Commission's directives from the 2015 GRC,[1548] SCE undertook a more detailed analysis to estimate the future cost of removal of SCE's millions of T&D assets. Rather than relying on aggregated ratios of historical retirement experience—which invited debates in prior

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[1546] Section 18.3 covers the first issue ("Life") and Section 18.2 covers the second ("T&D Net Salvage").
[1547] In the 2012 GRC, the Commission stated that aged data is likely to be more reliable than SPR data. D.12-11-051, p. 684.
[1548] D.15-11-021, Ordering Paragraph (OP) 9.i. at pp. 554-55.

GRCs about whether SCE's experts' judgment was substantiated, whether it is reasonable to assume that future experience will mimic past experience, whether SCE's proposals were out of line with what utility commissions had authorized for other utilities, etc.—SCE was asked by the Commission to provide substantially more quantitative data about its assets in this GRC. To do so, SCE estimated the future cost of removal by (a) separating major plant accounts into similar groups of assets and identifying the recent cost per unit to retire, (b) applying those per-unit costs to the total surviving plant balances; and (c) pairing the per-unit cost analysis with the *life* analysis.

The results of the labor-intensive study substantiated what SCE claimed for years—the Company's authorized net salvage rates are not set at a level that appropriately assigns the future cost of removal to the customers benefiting from their service.

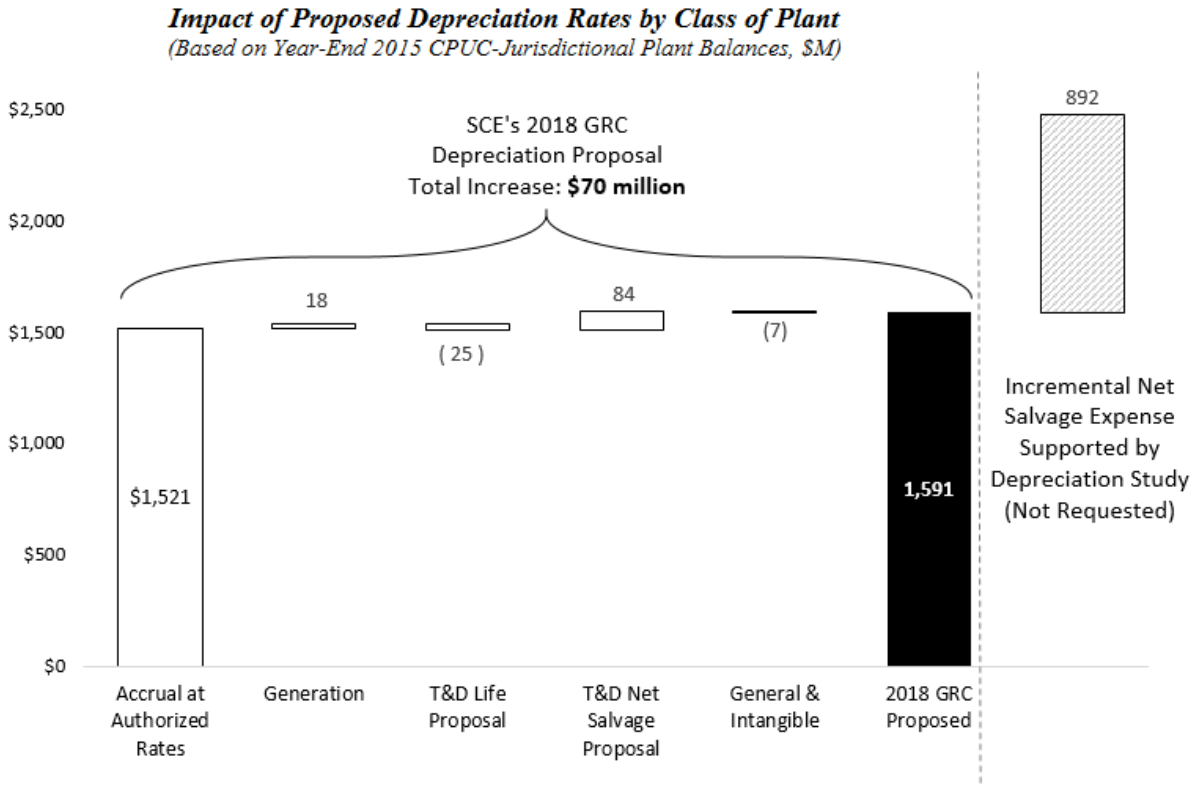
If SCE under-collects depreciation (as a result of an imprecise prior forecast, or a Commission decision that approved lower rates than what was required) the under-collection is necessarily allocated to future customers, requiring rate increases to accomplish the "catch-up." As a result, future customers will be unfairly burdened with paying for assets that today's customers enjoy. The Commission has long adopted an accrual method in California, where expenses are matched with revenues when the expenses are incurred, not when they are paid. In the Commission's words, "[a]ccrual accounting for removal costs is fair to ratepayers because it ensures that ratepayers pay for the removal costs of those assets that serve them, and pay no removal costs for assets that do not serve them."[1549]

Pursuant to SCE's study, the full forecast for T&D net salvage *alone* would require SCE to collect $976 million incremental-above-authorized dollars every year.[1550] As discussed in the Policy section above, SCE elected not to seek this incremental increase all at once, given the imperative need to balance time-sensitive infrastructure replacement and other initiatives to modernize the grid, on the one hand, with rate stability for our customers, on the other. Section 18.5, below, provides context on the Commission precedent for applying "gradualism" to moderate depreciation rates, and also addresses thoughtful questions from the assigned ALJs about how the Company uses depreciation expense revenues and what consumer protections are in place to ensure that those funds are used for their intended purpose.

[1549] D.07-03-044, p. 226.

[1550] The impact to 2018 depreciation expense is even higher because as plant balances increase, depreciation expense will increases as well.

As shown in the figure below, SCE requests a $70 million increase (approximately five percent) in its depreciation expense compared to what the Commission authorized in the 2015 GRC.[1551]



Note: The far left bar in the figure above shows a different number ($1,521M) from Table I-1 ($1,656) for two reasons: (1) It is calculated using only year-end 2015 plant balance instead of the full year 2015 recorded plant balances; and (2) it represents CPUC-jurisdictional depreciation expense only.

ORA seeks to reduce SCE's total request by $5.5 million. TURN seeks a $64.6 million reduction. Considering that SCE's overall depreciation proposal is $1.6 billion, the difference between SCE and TURN is relatively small, isolated to just five areas (Column G in the table below):[1552]

[1551] Exhibit SCE-09, Vol. 3A2, p. 4 (calculated based on year-2015 CPUC-jurisdictional plant balances).
[1552] *See* Exhibit SCE-25, Vol. 4, p. 2.

Comparison of Depreciation Expense Proposals
Based on Year-End 2015 CPUC Jurisdictional Plant ($M)

Line No.	Item	SCE Proposed	ORA Proposed	Δ from SCE	TURN Proposed	Δ from SCE	Rebuttal Chapter
A	B	C	D	E=D-C	F	G=F-C	H
1.	Authorized Depreciation Expense	$1,521.3	$1,521.3	-	$1,521.3	-	
2.	**T&D Proposals**	**58.5**	**58.5**	**-**	**17.4**	**(41.2)**	
3.	T&D Net Salvage	83.7	83.7	-	55.4	*(28.3)*	II, VII
4.	Account 369 Life Proposal	(1.0)	(1.0)	-	(13.9)	*(12.9)*	VI, VII
5.	Uncontested Life Proposals	(24.1)	(24.1)	-	(24.1)	-	
6.	**Generation Proposals**	**18.3**	**12.9**	***(5.5)***	**(5.1)**	***(23.4)***	
7.	Generation Decommissioning	0.1	0.1	-	(1.6)	*(1.7)*	III
8.	Solar PV Life	5.4	(0.1)	*(5.5)*	(0.1)	*(5.5)*	IV
9.	Hydro Production	10.5	10.5	-	(5.7)	*(16.2)*	V
10.	Other Generation	2.3	2.3	-	2.3	-	
11.	**General and Intangible**	**(7.1)**	**(7.1)**	**-**	**(7.1)**	**-**	
12.	**Change from Authorized**	**69.8**	**64.3**	***(5.5)***	**5.2**	***(64.6)***	
13.	**Total Proposed**	**1,591.0**	**1,585.6**	***(5.5)***	**1,526.4**	***(64.6)***	

However, the importance of forecasting the total future cost of removal should still command the Commission's full attention. That is, because while SCE's application of gradualism makes its pending request not far from TURN's overall, the parties' proposed methods for addressing the largest difference between them (T&D net salvage) are very different. SCE's net salvage proposal represents a modest step toward meeting the objectives of straight-line cost allocation and intergenerational equity principles this Commission has long guarded.[1553] SCE has answered the hard question of how much cost of removal is required to be collected, evenly, over the average remaining service life of its assets using explicit assumptions about inevitable future inflation.

[1553] *See, e.g.*, D.07-03-044, p. 207 ("The Commission determines depreciation expense on an accrual basis using the straight-line, remaining life method described in Commission Standard Practice (SP) U-4"); D.14-08-032, p. 588 ("Depreciation expense is recognized for ratemaking purposes on a 'straight line' basis over the estimated remaining average life of the asset in equal installments in accordance with Commission Standard Practice U-4."); D.84-06-111, p. 49, 15 CPUC2d 232 ("[T]he deferral of the charging of depreciation expense to a later period, even though the plant has been consumed by current ratepayers, would be unreasonably burdensome and inequitable to later ratepayers."); *See id.*, p. 54 ("The Commission sees no reason to depart from such [straight-line] practices and reaffirms its dedication to the classical features of remaining life depreciation as set out in Standard Practice U-4."); D.88-12-085, p. 11, 30 CPUC2d 299 ("For ratemaking, we have consistently adopted a policy of using straight-line remaining life depreciation as detailed in U-4 for the computation of depreciation rates.").

TURN ducks that important question, and its expert disclaims any expertise in advising the Commission about what should be done to collect the amounts SCE's study clearly justifies.[1554] Instead, TURN's approach would defer costs by treating depreciation no differently than maintenance expense. The Commission has considered and rejected similar proposed approaches by TURN in the past and should do so again here.

18.1. Foundational Overview

For ratemaking purposes, depreciation expense is designed to allow a utility to recover the costs it incurs to buy, install, and remove assets over the useful life of the assets. The Commission has long determined depreciation expense on an accrual basis[1555] using the straight-line, remaining life method described in Commission Standard Practice (SP) U-4, *Determination of Straight-Line Remaining Life Depreciation Accruals*, dated January 3, 1961.[1556] Allocating both the original cost of the investment *and* the future cost of removal using straight-line remaining life achieves the Commission objectives of intergenerational equity. "This systematic recovery of asset costs over the useful life is important for intergenerational equity, because asset life may span several generations of ratepayers who benefit."[1557]

As the Commission explained in a 2007 PG&E rate case decision, SP U-4 uses the following formula to calculate the annual depreciation expense accrual:[1558]

$$\textbf{Depreciation Expense} = \frac{\text{Plant Balance} - \text{Reserve} - \text{Gross Salvage} + \text{Cost of Removal}}{\text{Remaining Service Life of Asset(s)}}$$

The terms in the formula above have the following definitions,[1559] which are included here for completeness and quick reference:

[1554] TURN, Dunkel, Tr. 18/2630.

[1555] Under an accrual basis of accounting, expenses are matched with revenues when the expenses are *incurred*, not when they are paid. By contrast, under a cash basis of accounting, the expenses are incurred when the cash is paid out.

[1556] D.07-03-044, p. 207. *See* Exhibit SCE-25, Vol. 4, Appendix A, pp. 15-63, for a copy of Standard Practice U-4.

[1557] D.14-08-032, pp. 588-89.

[1558] D.07-03-044, p. 207.

[1559] These definitions are substantially similar to those set forth by the Commission in D.07-03-044 at pp. 207-208.

a. **Plant balance** is equal to the original cost of assets used to provide service to customers. In this brief, SCE uses "surviving plant balances" to describe the assets currently serving SCE's customers.

b. **Reserve**, also known as "accumulated depreciation," is the accumulated depreciation expense recorded to date for existing plant-in-service. Accumulated depreciation is an offset to rate base.[1560] That is, as the reserve increases, rate base decreases, all other things equal. As explained in Section 18.5, below, the reserve is not a "pot" or "fund" of money; rather, it is an accounting ledger that records the revenues already collected from customers to pay for depreciation expense, which guards against double-collection in the future. When SCE retires and removes a given asset, an accounting entry is made to reduce the reserve balance accordingly.

c. **Net Salvage** is gross salvage less cost of removal. If the cost of removal is more costly than the scrap value of the assets, as is usually the case for T&D plant, net salvage will be negative.[1561]

    a. **Gross salvage** is the estimated future scrap, sale, or reuse value of the assets upon retirement. Gross salvage is allocated over the lives of assets as a reduction to depreciation expense. When received, gross salvage increases the reserve balance.

    b. **Cost of removal** is the estimated future cost to remove existing plant-in-service. Because the cost of removal is often so much higher than the (often negligible) gross salvage value, sometimes the term "cost of removal" is used interchangeably with "net salvage."

    c. **Remaining life** is the expected average remaining life of plant-in-service.[1562] With each GRC, to the extent the adopted remaining lives are revised, the annual depreciation rate will be updated as well.[1563]

[1560] When rate base is reduced, so is the associated return and income taxes.

[1561] In depreciation studies, net salvage is often stated as a ratio of future net salvage divided by the original cost of installation. This is otherwise known as a net salvage ratio, or net salvage rate (NSR).

[1562] *See* Section 18.3, below.

[1563] D.84-06-111, p. 52, 15 CPUC 2d 232 ("Standard Practice U-4, and its predecessor documents dating back to 1952, have specifically recognized the necessity of updating of remaining lives during the intervening years between complete studies.")

18.2. T&D Net Salvage

The goal of a net salvage analysis is to estimate the future nominal cost to retire *all* of the surviving plant in service.[1564] This future cost is then divided by the remaining life of the assets to determine how much net salvage should be allocated to current customers. SCE was the only party in this proceeding to perform such an analysis, and it did so in two ways—using a "traditional" ratio analysis,[1565] and using a more detailed and data-rich per-unit analysis.[1566] Both analyses achieve SP U-4's objective of estimating the future cost to retire SCE's surviving assets and providing a basis for the straight-line allocation to the customers benefiting from the assets.[1567]

Overall, the results of SCE's per-unit analysis do not differ substantially (in the aggregate) from a traditional analysis, and both are consistent with SP U-4.[1568] Importantly though, SCE's detailed per-unit analysis sheds light on, and substantiates, SCE's position, in this and prior rate cases, that authorized net salvage rates are under-allocating the future cost to retire assets to the current customers who enjoy their benefits.

SCE's account-specific analyses produced the following results, with the asterisks denoting the accounts for which a per-unit analysis was also performed (and boxes denoting accounts where SCE applied gradualism):[1569]

[1564] *See* Exhibit SCE-25, Vol. 4, Appendix A, p. 27, Standard Practice U-4 at p. 12 ("Future net salvage as included in the accrual equation represents an estimate of the dollars which will be realized from the future retirement of all units now in service.").

[1565] A "traditional" ratio analysis compares the net salvage experienced in today's dollars to the original cost to install the asset. When applied to the surviving plant-in-service, this ratio provides an estimate of the level of future net salvage. Exhibit SCE-25, Vol. 4, pp. 15-17.

[1566] *Id.*

[1567] Exhibit SCE-25, Vol. 4, p. 12.

[1568] Exhibit SCE-25, Vol. 4, pp. 15-17.

[1569] Exhibit SCE-09, Vol. 3, p. 7.

SCE's Proposed Net Salvage Ratios for T&D Accounts

FERC Acct	Description	2015 GRC Authorized	Study Results	25% Above Authorized	SCE's NSR Proposals
A	B	C	D	E=C*1.25	G=Lesser of D or E
Transmission Plant					
352	Structures and Improvements	35%	35%	44%	35%
353	Station Equipment	15%	10%	19%	10%
354*	Towers and Fixtures	60%	185%	75%	75%
355*	Poles and Fixtures	72%	499%	90%	90%
356*	Overhead Conductors and Devices	80%	210%	100%	100%
357	Underground Conduit	0%	0%	0%	0%
358	Underground Conductor and Devices	15%	25%	19%	19%
359	Roads and Trails	0%	0%	0%	0%
Distribution Plant					
361	Structures and Improvements	25%	30%	31%	30%
362	Station Equipment	25%	50%	31%	31%
364*	Poles, Towers and Fixtures	210%	488%	263%	263%
365*	Overhead Conductors and Devices	115%	538%	144%	144%
366*	Underground Conduit	30%	401%	38%	38%
367*	Underground Conductor and Devices	60%	261%	75%	75%
368*	Line Transformers	20%	47%	25%	25%
369*	Services	100%	387%	125%	125%
370	Meters	5%	0%	6%	0%
373	Streetlights	30%	100%	38%	38%

** Used a per-unit analysis to arrive at proposed net salvage rates*

18.2.1. Evolution of Net Salvage Analyses

As net salvage rates have grown increasingly negative, TURN and SCE have continued to differ about the appropriate way to recover the significant associated expense. Under "traditional" ways of estimating net salvage, SCE and the Commission have relied on the historical ratio of recorded net salvage to recorded retirements.[1570] TURN has criticized the way SCE implemented the traditional approach in the past, and TURN's criticisms have resonated to some extent with the Commission. In particular, TURN questioned whether SCE's experts' use of qualitative judgment (to modify the ratios) was substantiated,[1571] whether it is sensible to assume that historical experience could be expected to be

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[1570] D.06-05-016, p. 206.

[1571] D.15-11-021, p. 396 (The Commission "warned SCE against over-reliance on judgment without further explanation," and TURN claimed that "SCE has not adequately explained its use of judgment[.]"). D.12-11-051, p. 685 ("If SCE provides more transparency of its application of judgment to depreciation forecasting, it will aid the Commission and intervenors in understanding SCE's analysis and the judgment applied to its forecast.").

mimicked in the future given the Company's changing retirement mix over time,[1572] and whether SCE's estimates are plausible compared to what other state utility commissions have authorized for other utilities.[1573] TURN has also raised questions about what role, if any, inflation should have in forecasting net salvage.[1574]

In grappling with these questions, the Commission has sought more detail and information from SCE to substantiate its proposals,[1575] but the Commission has appropriately declined to modify the bedrock principles that underpin depreciation, namely that:

- the costs of installing and removing assets should be allocated to the customers benefiting from those assets;[1576]
- the straight-line remaining life accrual method is preferable to cash-basis or "pay as you go" methods that kick the can down the road;[1577]
- deferral to future generations is generally to be avoided unless a more "gradual" approach to increasing depreciation expense is appropriate in a given time period given the balancing of interests;[1578] and
- the estimated future cost of removal will be impacted by inflation.[1579]

In the 2015 GRC, the Commission sought to address concerns about SCE's net salvage estimates by ordering the Company—in this GRC—to "provide considerably more detail in support of its net

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[1572] In the 2015 GRC, the Commission likely established its second depreciation directive in response to TURN's criticism that a changing retirement mix may result in different future NSRs than those experienced in the past. D.15-11-021, p. 418.

[1573] D.12-11-051, pp. 669-670 ("SCE solely relies on historical data and judgment. TURN views SCE's historical data as unreliable, skewed to high negative net salvage, and instead looks to comparison with industry averages and its own expert's judgment."). *See also* D.15-11-021, pp. 416-17 (ORA relied on industry averages to seek approval of less negative NSRs for SCE in the 2015 GRC, and the Commission agreed). In the 2015 GRC, though the Commission adopted some NSRs in part based on a review of industry averages, it stopped short of requiring that SCE—in this GRC—undertake an industry comparison.

[1574] *See, e.g.*, D.06-05-016, p. 193.

[1575] *See, e.g.*, D.12-11-051, pp. 683-686, in which the Commission sought additional information about SCE's cost of removal estimates, its allocation practices, and its proposals relative to industry averages.

[1576] *See, e.g.*, D.15-11-021, p. 394 ("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.").

[1577] *See* discussion in Section 18.2.5, below.

[1578] *See* precedent from PG&E's 2014 GRC, discussed in Section 18.5.1, below.

[1579] D.14-08-032, p. 591 ("There is an implicit inflation element in SP U-4"); D.07-03-044, p. 227 ("[T]he accrual method set forth in SP U-4 … results in a conservative projection of future inflation that probably understates future removal costs in nominal dollars.").

salvage proposals for at least five of the largest accounts," specifying the minimum detail such an analysis would require. The directives required SCE to produce:

(1) A quantitative discussion of the historical and anticipated cost of removal "on a per-unit basis" for large asset classes of plant;

(2) A quantitative discussion of the historical and anticipated future retirement mix, with an explanation of the key factors assumed in changing or maintain this mix; and

(3) A quantitative discussion integrating SCE's life analysis with its cost of removal analysis.[1580]

SCE took the Commission's directives seriously and embarked on a rigorous and data-rich three-step analysis.[1581] First, SCE divided its five largest accounts (plus four additional ones)[1582] into sub-populations of like assets and calculated an average cost per-unit to retire using recorded data from the prior seven years. This addressed the directive requiring that SCE analyze anticipated changes in "retirements among different asset classes."[1583] SCE's experts' judgment focused on identifying subpopulations for its analyses.

Second, SCE applied the per-unit costs to its surviving plant quantities. This step corrects for the problem of assuming that SCE's future retirement mix will simply mimic its historical experience because the costs are tied to *surviving* plant-in-service. This significant improvement also sidesteps the need to apply often contested judgment to modify the study results for factors such as the age of retirements, retirement mix, levels of inflation, etc. that would otherwise be assumed to be the same in the future as they had been in the past.

Third, SCE paired the unit costs with the results of its largely uncontested life analysis to estimate the timing (and, by extension, the level of inflation) at the time of future retirements.

Thus, SCE determined (a) the per-unit cost to retire different classes of assets in the recent past; (b) how many units it has on its books for each class of assets; and (c) when it expects to retire those assets. The process is simple and intuitive, but requires many man-hours to divide the assets into sub-populations and then pair the per-unit cost estimates with the life analyses.

[1580] D.15-11-021, p. 398 and OP 9.i. at pp. 554-55.

[1581] For a detailed description of the analysis, *see* Exhibit SCE-09, Vol. 4, pp. 11-30 & pp. 45-50.

[1582] The accounts analyzed on a per-unit basis account for 85% of the total proposed cost of removal expense. Exhibit SCE-09, Vol. 4, p. 12.

[1583] D.15-11-021, OP 9.i.(ii). at p. 555.

18.2.2. SCE's Per-Unit Analysis Is Both Rigorous and Intuitive

Here is an illustrative example of the Company's per-unit analysis, which, for simplicity's sake, assumes 0% inflation. Assume the utility has 100 distribution assets in Account 368 surviving today in its service territory. The assets can be grouped into three sub-populations[1584] based on similar characteristics: 50 overhead transformers, 30 underground transformers, and 20 fuse holders. In the last seven years, it cost SCE an average of $500 to retire each overhead transformer, $1,500 to retire each underground transformer, and $150 to retire each fuse holder. To determine how much it would cost today to retire all 100 assets, the answer would be computed as follows, by multiplying the per-unit cost to remove (for each subpopulation) by the number of units in service:[1585]

Subpopulation	Cost to retire	Units in Service	Cost to Retire Today
A	B	C	D=B*C
Overhead Transformers	$500	50	$25,000
Underground Transformers	$1,500	30	$45,000
Fuseholders	$150	20	$3,000
Total			**$73,000**

Assume that, on average, the assets in this account are expected to survive another 25 years. It would not comport with straight-line depreciation to collect the $73,000 all at once; rather, an even allocation is achieved by dividing the $73,000 by 25, yielding the appropriate *annual* accrual to assign to current customers, which is $2,920 (again, assuming zero inflation).[1586]

SCE performed the above analysis for millions of assets worth billions of dollars, which involved meticulously dividing nine different FERC accounts into 27 subpopulations, and pairing their per-unit cost to retire with the results of Dr. White's life analysis.[1587] Although the methodology is straightforward to compute, it is nonetheless labor- and data-intensive to divide the accounts into subpopulations and perform the statistical pairing with the life analysis.[1588] These steps are critical,

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[1584] The Commission's directive required that subpopulations be identified by isolating 15% of the plant balance in a given account. D.15-11-021, p. 398.

[1585] A real-world example of SCE's per-unit analysis is set forth in Mr. Varvis' testimony, Exhibit SCE-09, Vol. 3, p. 17.

[1586] Under the traditional method, the net salvage analysis is performed at the more aggregated (plant account) level, not using sub-populations. It also uses the cost of original installation, whereas the per-unit approach does not. See a formulaic depiction of the difference in Exhibit SCE-09, Vol. 3, pp. 16-17.

[1587] *See generally* Exhibit SCE-09, Vol. 3, pp. 12-20 & 45-50.

[1588] Exhibit SCE-25, Vol. 4, p. 9, and Dr. White's testimony in Exhibit SCE-09, Vol. 3, pp. 49-50.

however, because, in the example above, if SCE retired a large number of fuseholders in the recent past (compared to underground transformers), the costs incurred for doing so would not be an appropriate indicator of what SCE is required to accrue to retire the balance of assets in the account, especially given that 30% of the account contains assets that are ten times more expensive to retire. The *weighting*, by subpopulation, offers a more granular picture of what is expected in the future than looking in the aggregate at what the Company recently spent.

When the Commission adopts NSRs in this case, which SCE produced in its study as described above, they are run through the Results of Operation Model—account-by-account—to produce accruals that are collected dollar-for-dollar in the revenue requirement.

18.2.3. TURN's T&D Net Salvage Analysis Aims At a Pre-Determined Result and Lacks Rigor

TURN's expert, Mr. Dunkel, performed his T&D net salvage "analysis" in reverse. He began by "driving certainly to a number" close to the *aggregate* average level of net salvage that SCE had incurred over a three-year period (2013-2015) across all eighteen non-land T&D accounts. He then added twenty percent to that aggregated number (a multiple of 1.2 above recently incurred overall expenses), and—without specific testimony or a single workpaper explaining his judgment—hard-coded different net salvage ratios into each of the T&D plant accounts, from which his proposed depreciation accruals were derived. Mr. Dunkel admitted in discovery responses that he input hard-coded NSRs for each account on a trial-and-error basis so that the outcome could and would yield a multiple of 1.2 across all accounts: "The Net Salvage Accrual amount that would result from that specific [hard-coded] 'Future Net Salvage Percent' [NSR] is one of the factors Mr. Dunkel considering [sic] in determining what specific 'Future Net Salvage Percent' [NSR] to recommend for that account."[1589] In other words, in choosing what to recommend for "X," Mr. Dunkel circularly examined the result X would produce for "Y," with Y being one of the factors that determined whether to recommend X.

Apart from starting with the end result in mind—*i.e.*, aiming for an accrual value in the aggregate to back into account-specific NSRs—Mr. Dunkel offered no analysis for why he drove to a multiple of 1.2 in the first place. Instead, he just describes his objective, which is to propose that SCE collect over this rate case cycle an amount equal to the average annual aggregate net salvage incurred in

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[1589] Exhibit SCE-25, Vol. 4, Appendix B, p. 24, Data Request SCE-TURN-014, Q. 1.

2013-2015 plus "any reasonable level of expected inflation adding 20 percent[.]"[1590] That is neither a rigorous analysis nor anything approximating a depreciation "study." Mr. Dunkel's analysis is actually no different from an O&M forecasting exercise. The goal of depreciation is to recover long-lived capital assets, including their cost to remove, evenly over their average service lives. As Dr. White testified, "maintenance expense is a current period charge to operations that is recognized when the expense is incurred . . . Future cost of removable [sic] would only be comparable to maintenance expense if accrual accounting were abandoned and cost of removal were charged to operations when incurred."[1591]

When asked under cross-examination whether he proposes the same 1.2 multiple for *any* utility whose actual incurred net salvage values he examines, he responded, yes "[u]nless there is a valid reason to do otherwise."[1592] Specifically, among the factors he considers in departing from the same 1.2 proposal he would make in any other utility's rate case, Mr. Dunkel said he examines a utility's actual reserves compared to what "the theoretical amount should that [*sic*] be."[1593] Presumably, if the net salvage rates were not allocating enough in the past, he would adjust them to "catch up" in the future. However, when asked for his expert opinion on what the theoretical amount should be for *SCE* to accrue, he first referred to "theoretical amount workpapers." He then indicated that he does not "[h]ave them with me right now, but they do exist." When reminded that he did not produce the purported workpapers in response to two data requests from SCE seeking back-up documentation on this subject (of the basis for the proposed NSRs), he said no workpaper would have been transmitted for a concept not in his written testimony, and then offered, "I did not use theoretical reserve to in any way modify what I was proposing for [the hard-coded values] in Column N."[1594]

The only reasonable conclusion to draw from Mr. Dunkel's testimony is that he proposed depreciation expense for 2018-2020 based on an accrual of 1.2 times more than what SCE had recently incurred—in the aggregate—for no reason other than that he used the same number in a different

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[1590] TURN, Dunkel, Tr. 18/2578.
[1591] Exhibit SCE-25, Vol. 4, p. 65.
[1592] TURN, Dunkel, Tr. 18/2578.
[1593] TURN, Dunkel, Tr. 18/2578.
[1594] TURN, Dunkel, Tr. 18/2591.

utility's proceeding.[1595] There was simply no analysis. No workpapers.[1596] No account-specific evaluation. No tie-back to the past, present, or future retirement mix.

In fact, when Mr. Dunkel was asked, under cross-examination, why a multiple of 1.2 was not used for every individual T&D account, rather than just as an overall multiple across accounts, he referred vaguely to "a number of factors" (unexplained in his testimony) but only pointed to two: the size of the accruals produced by each proposal and the difference between using three- versus five-year averages.[1597]

In the end, by not providing the reasons for selecting individual net salvage rates for each account, Mr. Dunkel is taking a "trust me" approach to setting depreciation expense, reducing the proposed accruals by hundreds of millions of dollars less than what SCE's rigorous study justified. While SCE bears the burden of proof as the applicant, TURN's account-by-account net salvage rates are grounded in so little substantiating detail that they cannot be taken seriously. In response to a question under cross-examination about whether he had any analyses to justify his proposed account-by-account NSRs, Mr. Dunkel said:

> [E]ach account or each number I went through and looked at various possibilities and considered everything, including the five-year average, the three-year average, current, proposed, et cetera, I made a selection. Another factor was it was close to the current, I might wait, more likely to adopt that, for example.[1598]

This unsubstantiated judgment is exactly what the Commission warned against in SCE's 2015 GRC, when it said, "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," as it does with SCE's per unit-analysis, "with statistical results and no countervailing evidence is identified. An adequate showing will avoid statements of judgment without supporting analysis or explanation."[1599]

[1595] *See* Exhibit TURN-05, pp. 50-51 (citing Decision of the Public Utilities Regulatory Authority, State of Connecticut, Docket No. 16-06-04, dated December 14, 2016, p. 46).

[1596] Mr. Dunkel provided workpapers showing how to arithmetically compute accrual values derived from hard-coded NSRs, but the answer to the more fundamental question—how the NSRs are derived—remained elusive.

[1597] TURN, Dunkel, Tr. 18/2589.

[1598] TURN, Dunkel, Tr. 18/2590.

[1599] D.15-11-021, p. 398.

It became clear under cross examination that Mr. Dunkel's judgment consisted of mixing-and-matching NSR proposals, aiming for an aggregate multiple of 1.2 for the resulting accruals. He even apparently inadvertently forgot to reconcile two versions of possible rates, one that he tested for his testimony, and one that he settled on for his workpapers. The latter contains a multiple of 6.4 for one account, many times more than the aggregate 1.2, without explanation. The discrepancy clearly showed that for Account 354 (for example), Mr. Dunkel considered an NSR of -50% *and* -35%, neither of which is substantiated nor explained by record evidence. This is important because SCE is proposing a -75% net salvage rate for this account, only 40% of what SCE's study results would justify (-185%). Mr. Dunkel's reliance on a hard-coded value of -35%, only after being questioned about an apparent prior version of TURN's trial-and-error rate-accrual proposal, is backed by no record evidence. The difference amounts to more than five million dollars of accruals for that account alone, or 20% of the difference between SCE and TURN (in the aggregate) for T&D net salvage as a whole.

Even if one were to accept that Mr. Dunkel made a simple mistake in not adequately vetting the quality of his prepared testimony against the workpapers, the Commission can and should draw an inference that Mr. Dunkel simply lacks credibility to counter the sound results produced by SCE's study. Mr. Dunkel's net salvage analysis differs—without good reason—from SCE's moderated proposal by about $25 million.[1600] It differs by almost *a billion* dollars from SCE's unmoderated forecast from the per-unit study. The next section explains the methodological flaws in TURN's analysis leading to this divide.

18.2.4. Forecasting the Future Cost of Removal Using Three Years of Recorded Expenses Leads To Invalid Results

Because TURN's forecast depends primarily—if not exclusively—on reaching a value twenty percent higher than the aggregate recent spending by the utility on cost of removal, TURN necessarily overlooks the *level* and *mix* of retirements anticipated to be removed in the future. This is essentially the quantitative data the Commission sought to understand better when it ordered SCE to use its per-unit analysis to quantitatively discuss "the key factors in changing or maintaining the per-unit [cost of

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[1600] Mr. Dunkel's testimony compares TURN's proposed 1.2 multiple to a proposal SCE is not even making in this proceeding, without acknowledging or disputing that SCE's tempered proposal yields a multiple of 1.25. *See* Exhibit TURN-05, p. 52, Table 7, column titled "Dr. White Study Results Net Salvage Accrual;" *see also* TURN, Dunkel, Tr. 18/2592.

removal]," and "the historical and anticipated future retirement mix . . . identifying and explaining the key factors in changing or maintaining this mix."[1601]

Ironically, it was TURN's advocacy in the 2012 GRC that led to a perception that SCE had over-weighted historical data and, in so doing, had relied on it too heavily to predict the future. TURN's expert witness had opined in that proceeding that "the Company has not performed any analysis to determine whether the mix of retirements reflected in its historical net salvage database reasonably represents the current mix of retirement."[1602] In a footnote, TURN's expert went into additional detail about what a *per-unit* analysis would show instead:

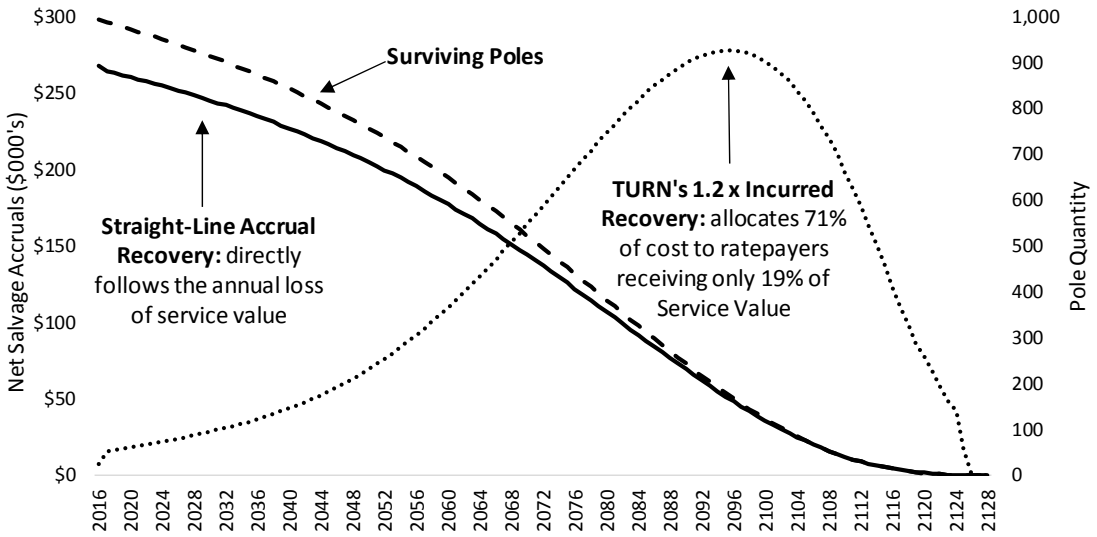
> For example, the Company's historical data may reflect a disproportionate level of retirements of lightning arresters at its substations in comparison to transformers. The level of investment in lightning arresters is much lower than the investment in transformers at SCE's substations, but the per-unit net salvage for lightning arresters may be appreciably more negative than that for transformers.[1603]

This astute observation—echoed by TURN's expert in the 2015 case about SCE's showing[1604]—can easily be applied to the testimony of TURN's new expert, Mr. Dunkel, who—by his own admission—did *nothing* to address how future retirements may in fact differ from what the company incurred in the recent past: "I did not make any adjustments to any of my proposals based on this [potential change in the future retirement mix], but it is a concern."[1605]

Setting net salvage rates approximately equal to what SCE recently incurred results in deferring net salvage costs to customers who do not receive their benefit. The resulting "accruals" under a proposal like TURN's match the pattern of cash expenditures, not the assets' service value. The figure below shows that under TURN's proposal, future customers would pick up the tab for retirement of assets that previous generations enjoyed. The Commissions straight-line accrual method, on the other hand, matches cost recovery with the service value of the assets.

[1601] D.15-11-021, p. 398.
[1602] Exhibit SCE-25, Vol. 4, p. 10 (referencing A.10-11-015, Exhibit WPSCE-25, Vol. 4, p. 110, which is an excerpt from the direct testimony of TURN's depreciation witness in the 2012 GRC).
[1603] *Id*.
[1604] Exhibit SCE-25, Vol. 4, p. 10 (referencing A.13-11-003, Exhibit WPSCE-25, Vol. 4, p. 114, which is an excerpt from the direct testimony of TURN's depreciation witness in the 2015 GRC).
[1605] TURN, Dunkel, Tr. 18/2632-33.

Comparison of Removal Cost Recovery Pattern[1606]
Straight-Line Recovery vs. TURN's 1.2 Multiple



One might ask why, under straight-line recovery, a utility might collect more cost of removal expense in the near-term three-year period than what it expects to spend over that same period? The answer is because the goal of depreciation is to *accrue* for the future cost of removal, not to collect "just enough" on a pay-as-you-go basis. Indeed, there is often a mismatch between the amount the utility collects annually, in rates, for future removal costs, on the one hand, and the amount it expends annually for current removal costs, on the other. The Commission has found that "this gap is normal and reasonable" because "the annual accrual of future removal costs will exceed annual expenditures when . . . new assets are being added faster than old assets are being removed and projected future removal costs are higher than current removal costs due to anticipated inflation."[1607] In prior cases, with respect to this gap, ORA has "acknowledge[d] that the unspent amounts collected will be used to prefund the cost of removal in the future."[1608] TURN's expert makes much ado about nothing when he points to the fact that SCE collects more than what it spends in a given year,[1609] because the goal is to collect

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[1606] Exhibit SCE-25, Vol. 4, p. 30, Figure II-7.
[1607] D.07-03-044, p. 211. *See also* D.06-05-016, p. 209 ("[B]y the nature of the established methodology where SCE is paying off current removal costs, while rates are being collected to fund future costs that are much higher than current costs, the [accumulated depreciation] balance, which is already over $2 billion, will continue to grow.")
[1608] D.13-05-010, p. 929.
[1609] Exhibit TURN-05, pp. 43-47.

customers' even share of costs now that are expected to be incurred in the future upon retirement of long-lived assets.[1610]

18.2.5. TURN's "Incurred Versus Accrual" Approach Recycles Various Versions of TURN's Prior Net Salvage Proposals, Which The Commission Has Repeatedly Rejected in Favor of Straight-Line Accrual

Mr. Dunkel calls his net salvage forecast methodology "incurred versus accrued" and disclaims its association with cash-basis accounting.[1611] But the general concept—to set depreciation rates based on an average of what the company recently incurred—is a reprise of what prior TURN experts have proposed (without success) under a different name.

For example, in PG&E's 2007 GRC, TURN asked the Commission to set PG&E's depreciation expense using what it called "normalized net salvage" as an alternative to SP U-4's straight-line remaining life method. "Under TURN's approach [in the 2007 case], the amount of removal costs recovered in rates would equal the annual average of PG&E's out-of-pocket costs for the previous three years or five years."[1612] The Commission explained that under that approach, "there will be no recovery of removal costs until after assets have retired and the associated removal costs have been incurred. TURN's method is, in effect, a form of cash-basis accounting."[1613] The Commission declined to adopt TURN's proposal, describing it as a "marked departure from the current accrual accounting for removal costs" and reasoned as follows:

> The purpose of using accrual accounting is to allocate to current ratepayers their *pro rata* share of the costs that will eventually be incurred to remove those assets that are currently being used to provide utility service. This treatment is in harmony with GAAP, the USOA, and long-standing Commission practice under SP U-4.[1614]

The Commission's reasoning from the 2007 PG&E case remains valid: Setting net salvage rates based solely on recently incurred net salvage experience "would require ratepayers to pay for removal costs incurred in prior years for assets that are no longer in service. As a matter of equity, we believe that ratepayers should pay only for those assets that currently serve them. *TURN's proposal fails this*

[1610] SCE addressed this point in Exhibit SCE-25, Vol. 4, p. 35.
[1611] Exhibit SCE-25, Vol. 4, Appendix B, pp. 30-32 (Data Request SCE-TURN-014 Q. 3).
[1612] D.07-03-044, p. 219.
[1613] *Id*. at p. 226.
[1614] *Id*.

test."[1615] Likewise, TURN's proposal in this case, which is essentially a reprise of its normalized net salvage proposal, fails the same test for the same reasons.

When TURN sought intervenor compensation for contributions it had made to PG&E's 2007 GRC, the Commission recognized that TURN had "objected to the way future removal costs were estimated in the GRC Settlement [between PG&E and the Division of Ratepayer Advocates, now ORA]" and described TURN's 2007 proposal this way: "TURN recommended that removal costs be based on a rolling three-year or five-year average of PG&E's recorded removal costs, which it called the 'normalized net salvage approach.'"[1616] The Commission disallowed half the time TURN spent advancing its normalized net salvage proposal because "we note that it had made a similar proposal in SCE's [2006] GRC Proceeding" and that "TURN did not prevail in the SCE proceeding and the issue is no longer novel."[1617]

On a third occasion, TURN proposed normalized net salvage in SDG&E's 2008 GRC, and then voluntarily reduced its own request for intervenor compensation in recognition that the Commission would not find its normalized net salvage proposal to be a substantial contribution to the result, citing the Commission's determination (above) that TURN did not prevail in PG&E's or SCE's cases and that the issue was not novel.[1618]

SCE acknowledges that other jurisdictions, outside California, may use methodologies akin to normalized net salvage, cash-basis or incurred-versus-accrued to set net salvage rates, including in Connecticut where Mr. Dunkel prevailed with his "1.2" proposal.[1619] However, in proposing to set net salvage rates based on a multiple of recent experience, TURN is essentially attempting to modify this Commission's long-standing straight-line accrual method set forth in Standard Practice U-4. SCE's GRC is not the appropriate place to adopt such a ratemaking change. When SDG&E tried in a 1981 GRC to propose an alternative to straight-line depreciation (using a "Comparable Dollar Method" that indexes the dollars spent for plant to a common year, and then determines the composite remaining life using these common dollars), the Commission rightly recognized that although U-4 was last revised in

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[1615] D.07-03-044, pp. 226-227 (emphasis added).
[1616] D.07-12-026, p. 15.
[1617] D.07-12-026, pp. 15-16.
[1618] D.08-11-053, p. 6 and p. 13.
[1619] *See* 334 P.U.R. 4th 167, Decision of the Public Utilities Regulatory Authority, State of Connecticut, Docket No. 16-06-04, dated December 14, 2016, p. 46

1961, at a time when inflation was of "little consequence," a utility-specific GRC would not be the right forum to depart from Commission policy: "[T]his is not the proper proceeding for contemplating these changes to our adopted ratemaking procedure."[1620]

Thus, even if the Commission were inclined to re-examine its fidelity to the straight-line remaining life accrual method—outlined in SP U-4 and supported by numerous Commission decisions spanning several decades[1621]—in favor of the incurred-versus-accrued or normalized net salvage approaches, doing so in this utility-specific GRC would not be appropriate. A rulemaking, either initiated by TURN or by the Commission on its own motion, is more appropriate than upending long-standing precedent based on Mr. Dunkel's questionable showing. While SCE does not agree that such a departure from SP U-4 is appropriate, if one is to be considered, it should be done with all affected stakeholders participating (including the state's other two large electric and possibly non-electric IOUs).

In the meantime, SP U-4 is clear that "future net salvage represents an estimate of the dollars which will be realized [spent] from the future retirement of *all units now in service*[.]"[1622] Nothing TURN's expert presented in this proceeding justifies departing from the Commission's SP U-4.

18.2.6. TURN's Criticisms of SCE's Per-Unit Analysis Lack Merit

Without challenging the merits of how SCE designed and accomplished its per-unit analysis, TURN makes five principal arguments criticizing SCE's approach, all of which lack merit. First, TURN argues that, because SP U-4 does not describe a per-unit analysis, SCE's study departs from SP U-4. Second, TURN concludes that, because SCE is the first electric utility to undertake such a thorough per-unit analysis, the results are automatically suspect. Third, TURN confuses the Commission's directives requiring a quantitative discussion of SCE's past and future retirement mix—on a per-unit basis—with questions it may have had in the past about SCE's cost assignment practices (*i.e.*, allocation of

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[1620] D.93892, 7 CPUC 2d 584, p. 140

[1621] D.04-07-022, pp. 255-56 ("Consistent with the Commission's Standard Practice U-4 . . . as well as standard practice throughout the electric utility industry, SCE calculated depreciation expenses using accrual rates based on the straight-line method using the remaining life technique."). D.84-06-111, p. 54, 15 CPUC 2d 232) ("Time has proven that consistent use of these procedures will meet the primary objective of depreciation which is, in the Commission's opinion, to recover, during its useful service life, the original cost of plant, not more, not less. The Commission sees no reason to depart from such practices and reaffirms its dedication to the classical features of remaining life depreciation as set out in Standard Practice U-4."); D.88-12-085, p. 11, 30 CPUC 2d 299. ("For ratemaking, we have consistently adopted a policy of using straight-line remaining life depreciation as detailed in U-4 for the computation of depreciation rates.").

[1622] D.86794 CPUC 49 (emphasis added), p. 81.

replacement costs to removal versus installation). Fourth, TURN resurrects a recurring theme that SCE's estimated future cost of removal is not credible when compared to what state utilities commissions have authorized for other companies. Fifth, TURN selectively attacks the quality of SCE's data and makes unsubstantiated generalizations from there.

18.2.6.1. SCE Fully Complied with the 2015 GRC Depreciation Compliance Directives and the Commission's Standard Practice U-4

As a threshold matter, no party disputes that SCE complied with the Commission's directives in the 2015 GRC to provide "considerably more detail in support of its net salvage proposals for at least five of the largest accounts," including detail responsive to the Commission's four requirements.[1623] ORA does not even dispute any of SCE's actual net salvage proposals,[1624] and simply asks the Commission to clarify whether it "meant to have Edison provide a more 'quantitative discussion' and 'considerably more detail in support of its net salvage proposals' or if the intent was to move the net salvage analysis method away from the traditional approach (as established in the SP U-4) to a per-unit analysis."[1625] This point is well taken, but as explained below, the per-unit analysis is not inconsistent with SP U-4, and SCE takes no position here about whether the directives from D.15-11-021 from the 2015 GRC should or will extend to future GRCs.

Ignoring that the per-unit analysis was ordered by the Commission and could not reasonably be expected to have contradicted the Commission's adopted depreciation methodologies, Mr. Dunkel nonetheless argues that SCE's per-unit analysis "abandon[s]"[1626] SP U-4. To the contrary, Dr. White testified that he "see[s] nothing in [Standard Practice] U-4 that would prohibit one from estimating future net salvage using the most rigorous method that one can do to estimate it."[1627] SP U-4 is not prescriptive in its discussion about the analytical approach or method required to arrive at an estimate of

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[1623] SCE's direct testimony devoted a full chapter to its per-unit analysis, directive-by-directive. Exhibit SCE-09, Vol. 3, pp. 11-20 (Chapter II, Sections A-B).

[1624] TURN's witness implied otherwise, testifying vaguely about ORA's "concern" with SCE's per-unit analyses that "properly questioned SCE's position." *See* Exhibit TURN-05, p. 15. However, on cross-examination, he could not articulate those concerns, stating that he "can't speak to what ORA intended[.]" TURN, Dunkel, Tr. 18/2567.

[1625] Exhibit ORA-21, p. 5.

[1626] Exhibit TURN-05, p. 15.

[1627] SCE, White, Tr. 17/2421.

future net salvage.[1628] Instead, it provides a broader discussion of factors to consider when evaluating future net salvage. For example, it acknowledges that removal costs are affected by "changes in labor expenses," and that there can be a difference in net salvage related to "units of different ages."[1629] It suggests that for "very accurate determinations[,] predicted salvage values by ages should be weighted with predicted retirements by age."[1630] SCE's per-unit analysis took into consideration these factors to arrive at an estimate of future net salvage.[1631]

Contrary to TURN's assertions, SCE's analysis did not abandon accepted depreciation practices; rather, it supplemented a traditional analysis with more detailed and granular data, and it applied a more forward-looking focus to estimating net salvage rates.[1632] That is consistent with the stated objective of SP U-4 to "set[] forth various factors influencing the determination of depreciation accruals and describe[] methods of calculating these accruals."[1633] SP U-4 recognizes that "past retirement experience of most utility plant is based on but a small portion of today's existing plant." This recognition highlights that the past net salvage experience may not provide the best estimate of what the utility expects net salvage to be in the future. SCE's analysis drew on numerous records, both to determine the recent net salvage[1634] on a per unit basis (in dollars) and to understand the mix of assets in the surviving plant balance (an estimate of the future). SCE's segmentation of FERC accounts into subpopulations (following the CPUC's directives) also follows the advice in SP U-4 that "if . . . there is a difference in characteristics or different market demand for units of different ages, the possibility of separate salvage estimates for different age groups should also be considered."[1635]

Had the Commission intended in the 2015 GRC decision to have SCE's net salvage analysis focus solely on the non-prescriptive methodology in SP U-4, authored in 1961, there would have been no need for it to issue the specific, step-by-step directives it did, which referred twice to "per-unit" analyses. In fact, the Commission's directives arose in large part from TURN's advocacy in prior cases.

[1628] Exhibit SCE-25, Vol. 4, p. 62 & Appendix B, p. 8 (Data Request TURN-SCE-035 Q. 01.a).
[1629] Exhibit SCE-25, Vol. 4, p. 13, citing Appendix A, p. 28 (SP U-4 at p. 13).
[1630] Exhibit SCE-25, Vol. 4, p. 13, citing Appendix A, p. 52 (SP U-4 at p. 37.
[1631] Exhibit SCE-25, Vol. 4, p. 13.
[1632] Exhibit SCE-25, Vol. 4, p. 12.
[1633] Exhibit SCE-25, Vol. 4, citing Appendix A, p. 20 (SP U-4 at p. 5).
[1634] D.14-08-032, p. 591 ("SP U-4 states that because removal costs are labor based, recent data is to receive greater weight.").
[1635] Exhibit SCE-25, Vol. 4, p. 13, citing Appendix A, p. 28 (SP U-4 at p. 13).

18.2.6.2. That SCE Prepared A First-Of-Its-Kind Study Does Not Diminish Its Value

TURN focuses on the lack of precedent for other electric utilities using a comprehensive[1636] per-unit analysis, but that is not a reason to cast aside SCE's study results. As Mr. Varvis testified, a per-unit analysis is, without question, costlier and more resource-intensive to produce.[1637] SCE committed time and resources to this effort, at a cost that was more than double what the traditional analysis alone would have required.[1638] It should surprise no one that time, cost, and data availability would discourage the ability of other companies from undertaking per-unit analyses at the level SCE did in this proceeding.[1639] Dr. White testified that per-unit analyses require a lot of data that most utilities simply do not have readily available.[1640] In his experience:

> [A] per-unit net salvage analysis of installation and retirement costs is the most desirable treatment of net salvage. Unlike other methods of analysis, the per-unit model is derived from the principle that the cost per unit to retire an asset is independent of the age of the asset when it is retired from service. As a practical matter, however, time and cost considerations (as well the availability of required data) often dictate a less rigorous analysis using a three to ten-year moving average of the ratio of realized salvage a cost of removal to associated retirements. Absent these constraints, Foster Associates would encourage conducting per-unit net salvage analyses in all depreciation studies.[1641]

18.2.6.3. SCE Met Its Burden To Show Why Its Assignment of Costs to Removal Is Reasonable

Rather than dispute the design of SCE's per-unit analysis, TURN offers a different interpretation of what the Commission sought when it directed SCE to study per-unit costs. TURN locates "wording in the [2015 GRC] Decision which shows an example [of] what the 'per unit' discussion of net salvage was

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[1636] As Mr. Varvis testified, one cannot maintain that this Commission *never* relied on per-unit analyses for given accounts because SCE has presented them in the past and the Commission does not always explain the factual basis on which it based its conclusions. For example, in the 2006 GRC, SCE separated the investment for several T&D accounts into various sub-populations, calculated per-unit retirement costs, and re-weighted these costs to reflect the surviving investment. That was substantially the same as the efforts SCE undertook in this proceeding, but this time SCE did so on a broader scale. Exhibit SCE-25, Vol. 4, pp. 11-12.

[1637] Exhibit SCE-25, Vol. 4, p. 9.

[1638] *Id*.

[1639] Exhibit SCE-25, Vol. 4, p. 9 (citing Dr. White's testimony in Exhibit SCE-09, Vol. 3, p. 39).

[1640] *See* SCE, White, Tr. 17/2416-17. *See also* Exhibit SCE-25, Vol. 4, p. 61.

[1641] Exhibit SCE-25, Vol. 4, pp. 60-61.

as stated in the Decision."[1642] Ignoring the broader context of the Commission's concerns in the prior cases, TURN focuses on a narrow example in the decision comparing SCE's per-pole cost of removal with that of a rural Texas utility.[1643] That section of the decision, comparing SCE's net salvage ratio with another utility's, has nothing to do with the per-unit analysis contemplated by the Commission's first three directives. The cited discussion regarding the difference in pole removal costs relates to the fourth directive, cost assignment, because the discussion specifically alluded to the potential that "SCE's *allocation* between COR [cost of removal] and cost of installation [being] part of the problem."[1644] The Commission had used the Texas utility example to address "concerns with SCE's showing on its allocation practices," not to its forecast net salvage methodology.[1645]

In any event, TURN's criticisms of SCE's cost assignment practices are unfounded. For replacement projects, the utility must separate removal activities from installation activities. That is because a portion of the labor involved in a replacement project is dedicated to installing the new asset (a capital addition), and a portion of the labor is dedicated to removing the old asset (cost of removal, which is an offset to the accumulated depreciation reserve). SCE's process for assigning costs to removal has been another area of contention between SCE and TURN.[1646] In the 2015 GRC, SCE relied on its outside expert's examination of cost assignment practices, and both TURN and the Commission thought the analysis was cursory.[1647] For this reason, among others, the Commission directed SCE—in this GRC—to set forth "[a]n account-specific discussion of the process for allocating costs to COR [costs of removal]."[1648]

[1642] Exhibit TURN-05, p. 14.
[1643] *Id.*
[1644] D.15-11-021, p. 419 (emphasis added). *See also* WPSCE-25, Vol. 4, p. 142.
[1645] Although the Commission expressed interest in SCE's net salvage rates compared to other utilities', it is not plausible to interpret the Commission's directives in the 2015 GRC to require production of analysis on that subject. The first three directives are necessarily Company-specific and inward-looking, requiring SCE to quantitatively: (1) examine its historical versus anticipated future cost-of-removal; (2) discuss its historical and anticipated future retirement mixes, identifying and explaining key factors in changing or maintaining the mix; and (3) integrate its life analysis with its net salvage analysis. Had SCE focused solely on cost assignment (i.e., installation versus removal cost), as Mr. Dunkel interprets the directives to require, or on how its net salvage rates compare to those of other utilities elsewhere in the country, it would not have been able to meet the first three directives of the 2015 Decision.
[1646] D.15-11-021, pp. 412-413.
[1647] D.15-11-021, p. 413.
[1648] D.15-11-021, OP 9.i.(iv). at p. 555.

In response to that directive, SCE detailed its cost assignment practices for large assets and for "mass plant," and demonstrated why its current process may actually be conservative relative to what corroborating studies (using thousands of recent replacement job work orders) would justify for cost of removal.[1649]

TURN ignored this analysis and instead incorrectly claimed that SCE is assigning more of its per-project costs to removal.[1650] To substantiate his claim, Mr. Dunkel pointed to evidence that the total cost of removal represents a greater proportional share of SCE's total company T&D investment, ignoring the fact that some projects represent asset unit replacements (including both removal and installation), some are new plant additions without removal, and some are only plant retirements without an installation. Projects can comprise varying asset mixtures with different assets and plant accounts. SCE offered detailed evidence why TURN's analysis was inaccurate,[1651] and that the total company share of removal cost investment was attributable to increased investment in replacement projects, not an increasing assignment to cost of removal

Specifically, SCE showed that the mix of new construction versus replacement work changed over the 2002-2015 time period due to load/customer growth and a focus on infrastructure replacement during different portions of this time period. So while the total cost of removal has increased over time, the ratio of cost assignment for removal versus installation for a particular property units in a project has remained unchanged. This is a simple reflection of the changing nature of SCE's work, and is not, as TURN incorrectly asserts, a modification to "amounts that previously would have been part of 'plant' amounts [to amounts that] are now included in the net salvage amounts."[1652]

The figure below, reproduced from SCE's rebuttal testimony, shows a summary of the mix between new distribution construction projects versus capital replacement projects over the same timeframe analyzed by TURN, 2002-2015:

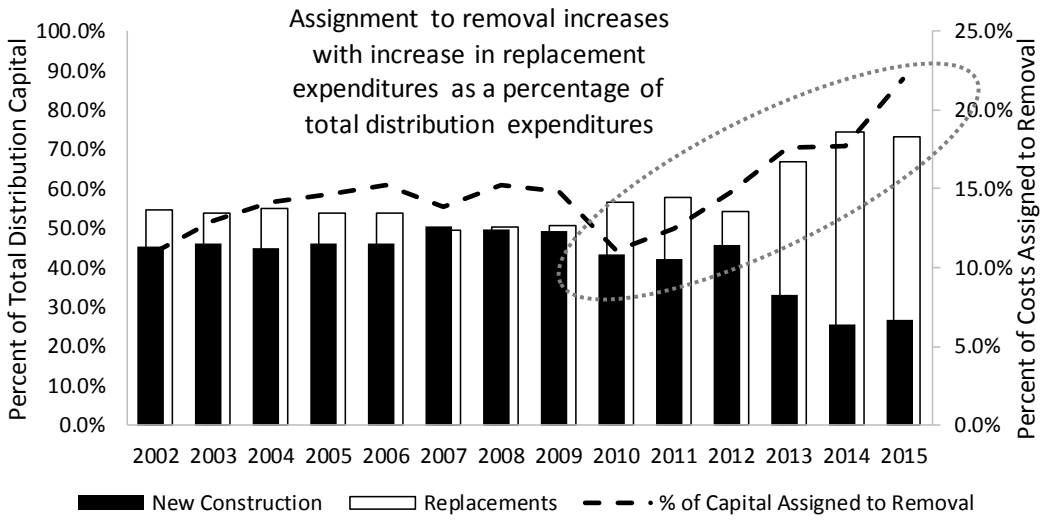
[1649] Exhibit SCE-09, Vol. 3, pp. 29-30.

[1650] TURN compared the total cost of "additions" to the total "cost of retiring" for Account 367 over the period 2002-2015 and concluded, erroneously, that "the percent that SCE is allocating to the COR has been increasing." Exhibit TURN-05, p. 17.

[1651] Exhibit SCE-09, Vol. 3, pp. 20-23.

[1652] Exhibit TURN-05, pp. 40-41.

Relationship of Changes in Investment Mix and Assignment to Costs of Removal[1653]



ALJ Wildgrube asked Mr. Dunkel about his allegation that SCE's cost allocation practices had been changing over time, and, when responding, Mr. Dunkel ignored SCE's rebuttal testimony (above). Instead, he reverted back to his total cost evidence (which is agnostic to the difference between replacement versus new construction projects), opining that "for some reason when they [SCE] do *a project* now a higher percent of the total cost of *that project* gets recorded as cost of removal than occurred in earlier years."[1654] Under cross-examination, however, when asked about his opinion that SCE has changed the proportion of removal costs assigned to "given project[s]," he quickly changed his testimony, contradicting both his oral and written[1655] testimony: "Not particularly in a given project. These are overall company numbers for each year."[1656] He also agreed, consistent with the graph above,[1657] that if the mix of replacement projects is increasing over time, overall, the company will

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[1653] Exhibit SCE-25, Vol. 4, p. 23, Figure II-5.

[1654] TURN, Dunkel, Tr. 18/2631-32.

[1655] In written testimony, Mr. Dunkel drew the same incorrect conclusion, noting that "[i]n a *single project*, new facilities may be installed ('additions') and existing facilities may be removed" and then implying that cost assignment practices have changed given that on a *total spend* basis, "the percent that SCE is allocating to COR has been increasing." Exhibit TURN-05, pp. 15-16 (emphasis added).

[1656] TURN, Dunkel, Tr. 18/2636.

[1657] The graph shows that the mix between new construction and replacement capital has changed over time and SCE has experienced a higher proportion of capital replacement spend in recent years. Contrary to Mr.

spend more on cost of removal *even though its cost-assignment practices have not changed at all*: "That is possible on a—yes, that is possible."[1658]

18.2.6.4. Comparing SCE's Experienced Net Salvage Ratios with Other Utilities' Authorized Amounts Has Limited Value

In the 2012 GRC, the Commission required SCE (in its 2015 GRC) to "include a better description" of a number of depreciation-related issues, including the mix of investments considered when forecasting a given NSR for an account.[1659] It also gave credence to an observation by TURN and ORA that SCE's NSRs are "often far outside industry averages for large T&D accounts" which it considered a "troubling fact, despite several factors which may reasonably drive those differences."[1660] So it ordered SCE to "provide testimony in its next GRC [2015] to provide more information about COR in asset accounts where SCE's proposed NSR is at least 25% more than comparable industry averages."[1661] That led to some debate in the 2015 case about which "industry average" to use (authorized, experienced/recorded, or requested). In the 2015 GRC decision, the Commission declined to again request industry-based comparison analyses in the 2018 GRC, and instead asked SCE to focus on its own retirement mix, unit data, assessment of the future, and cost assignment practices.

TURN, however, harkened back to industry data, contending that SCE's proposed net salvage rates were "way out of line with other jurisdictions."[1662] But TURN's conclusion relied on two incorrect assumptions: (1) comparing SCE's untempered net salvage rates to the industry authorized net salvage rates is appropriate; and, (2) all companies that file FERC Form 1 data are comparable. On the first point, SCE argued in rebuttal that *authorized* net salvage rates are not as revealing as *experienced* rates because utility commissions often consider bill impacts (for example) when approving depreciation rates, not just the underlying data.[1663]

Dunkel's testimony, SCE's unchanging cost assignment practices at the project level do not affect why removal costs increased as a percentage of total spend.

[1658] TURN, Dunkel, Tr. 18/2638-39.

[1659] D.12-11-051, p. 685.

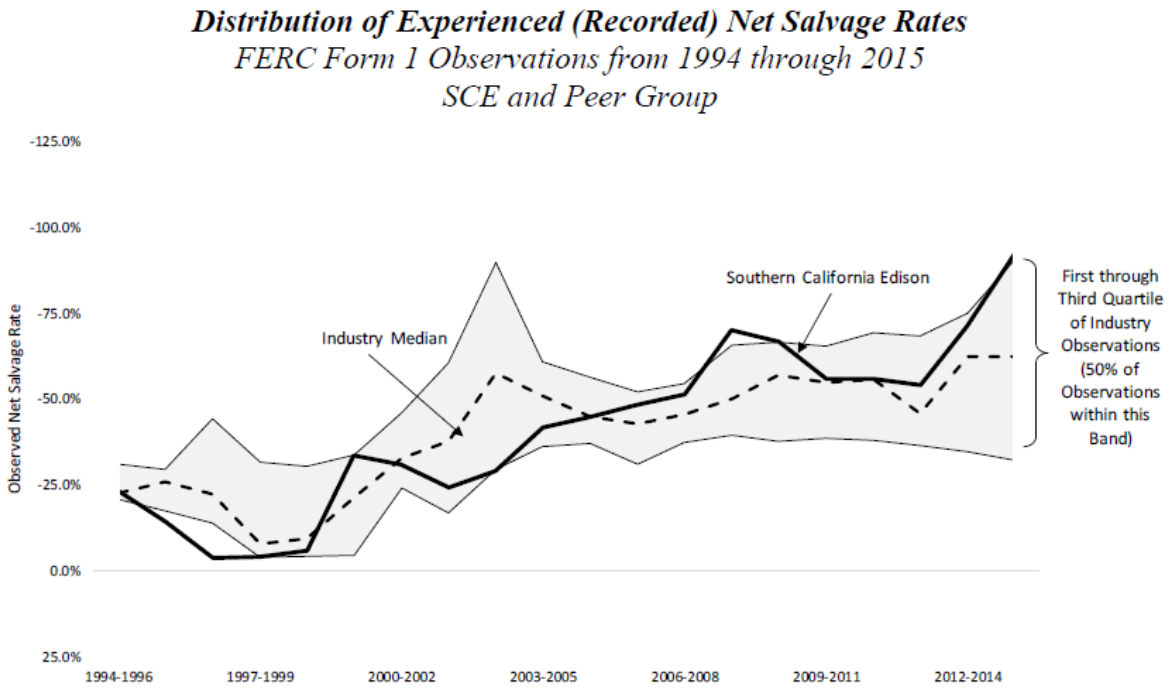
[1660] D.12-11-051, p. 685.

[1661] D.12-11-051, p. 686.

[1662] Exhibit TURN-05, p. 36.

[1663] Exhibit SCE-25, Vol. 4, pp. 17-19.

On the second point, SCE sought to compare its experienced net salvage ratios with that of peer utilities, defined as those of comparable size, asset mix, and population density, and showed that SCE's experienced ratios are not outliers:[1664]



When TURN's counsel cross examined SCE Witness Alan Varvis, the line of questioning appeared at least in part interested in pointing out that the depreciation methodologies adopted in the jurisdictions of SCE-defined peers in some cases differed from straight-line remaining life accruals (SP U-4). That is beside the point, and not reason to invite the Commission to depart in this utility-specific GRC from the methodology it has long championed. Rather, the purpose of SCE's industry comparison was not to justify its net salvage rates,[1665] but to respond to TURN's claim that SCE is an outlier in the industry. It is not. The per-unit analysis was specific to SCE's assets, and established the net salvage ratio that would accomplish SP U-4's objective of straight-line accruals.

In the same vein, Dr. White's net salvage proposals in other jurisdictions, who do not follow SP U-4's straight-line remaining life method, do not bear on his proposals in this proceeding, where SCE

[1664] Exhibit SCE-25, Vol. 4A, p. 18-A.

[1665] The shortcomings of industry comparisons are many, which is why SCE's direct showing did not rely on industry comparisons (and perhaps why the Commission elected not to direct one in the 2015 GRC). Exhibit SCE-25, Vol. 4, pp. 68-69.

adhered to SP U-4. As this Commission has concluded, "the results of a depreciation study using Standard Practice U-4 should be adopted absent evidence that the result from that uniform methodology is skewed."[1666] TURN has presented no such evidence.

18.2.6.5. TURN's Criticisms of SCE's Data Do Not Cast Doubt On The Integrity of SCE's Study

TURN lodges diffuse objections to SCE's data but they lack merit for four basic reasons.

First, TURN agrees with the vast majority of SCE's proposed estimated service lives for T&D mass plant, which rely on the same data TURN criticizes in the per-unit analysis. TURN cannot have it both ways; if the data legitimately shows that the service lives are getting longer (which reduces depreciation expense, all other things being equal), it cannot also cast aspersions on data that shows future net salvage is increasing (especially given that the longer an asset is in service, the more it will cost to replace it in the future, just by operation of inflation).

Second, TURN points to "serious errors in the actuarial data in the experience years 2002-2008," presumably because SCE started using PowerPlan to store its data in 2008. This is rank speculation, belied by the response SCE gave to TURN in discovery (that TURN ignored):

> To prepare for the depreciation showing in this 2018 GRC, SCE double-checked the PowerPlan[] data for years 2002 through 2008 against FERC Form 1 pages 204-207 from each of the respective years. SCE compared all activity and balances presented on the Form 1 to the tabulated activity by type (*i.e.*, additions, retirements, transfers, etc.) to verify that the data is consistent and appropriately classified.[1667]

FERC Form 1 data provides an industry standard for utility accounting and reporting of plant activity. The transactions from the 2002-2008 period represent plant ledger records of SCE's actual experience with service life characteristics of the plant-in-service prior to migrating to PowerPlan in 2008.

Third, to the extent SCE discovered pockets of isolated data problems—which is inevitable for a large utility with millions of assets—it quantified and accounted for them appropriately. For example, SCE acknowledged to TURN during discovery that it had discovered an error in how vintages were being assigned to retirements caused by a system issue related to the "Y2K" conversion at the start of the century. As SCE explained, the impact of this issue was confined to a small group of retirements

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[1666] D.09-11-032, p. 11.
[1667] Exhibit SCE-25, Vol. 4, p. 54.

with vintages around the year 2000. Once this issue was identified during the discovery phase of the proceeding, SCE reviewed the data and requested that SCE's depreciation expert, Dr. White, run a supplemental life analysis to ascertain any effects on SCE's proposals.[1668] Dr. White concluded based on the results of his analysis that the Y2K data issue provided an insufficient basis for adjusting any of his recommendations because the impacts were minimal. As another isolated example, SCE found a small population of retirements with negative ages (*i.e.*, a 2010 vintage asset being retired in 2009). The affected data constituted less than 0.2% of retirements, with no bearing on the depreciation estimation.[1669] SCE thoroughly addressed TURN's other criticisms in its rebuttal testimony.[1670]

Fourth, questions about whether SCE's net salvage data reflected the proper age of assets at retirement has nothing to do with a per-unit net salvage analysis, which computes the cost of removal regardless of the age of the asset.[1671] That is one way in which the traditional net salvage analysis differs from per-unit analysis, the latter of which applies current per-unit net salvage ratios to SCE's vintaged surviving plant balances. This approach helps ensure that the historical data is appropriately weighted to reflect the future (and not just the past) retirements.

18.2.7. Inflation Considerations Are Unripe In This GRC, and Related Proposals Are Undeveloped In Any Event

One benefit of the per-unit analysis is that it makes inflation assumptions explicit. Under the traditional approach, the inflation embedded in the historical cost of removal is assumed to carry over into the future at the same rate. The per-unit analysis does not make the same blunt assumption. It first determines the total cost to remove all assets today based on recent cost data and current quantity data; it then layers on an explicit inflation assumption tied to the life analysis. Had SCE assumed a 2.72% inflation rate,[1672] the annual accruals for future cost of removal attributable just to inflation would be almost one billion dollars.[1673]

[1668] SCE provided the results to this analysis in response to a data request. *See* Exhibit SCE-25, Vol. 4, Appendix B, pp. 9-11.
[1669] *See id*, Appendix B pp. 15-16.
[1670] Exhibit SCE-25, Vol. 4, pp. 55-58.
[1671] Exhibit SCE-25, Vol. 4, p. 62.
[1672] *See* Exhibit SCE-09, Vol. 3, p. 5, fn. 4. For an explanation about the basis of the inflation assumption, refer to WP SCE-09 Vol. 03, Book A, p. 24 (Capital Escalation).
[1673] Exhibit SCE-09, Vol. 3, p. 4.

But SCE moderated its proposal by an amount that effectively reflects an inflation rate *below* zero, which makes this important issue (what inflation rate to apply, whether to apply a net present value analysis, etc.) unripe for resolution in this GRC. In fact, SCE's pending proposal is $86 million below the total amount of accruals needed to collect for future cost of removal of all of SCE's existing assets assuming zero inflation, as computed in the table below using record evidence.

Difference Between SCE's Proposal and Net Salvage Accruals at 0% Inflation

FERC Account	Year-End 2015 CPUC Jurisdictional Gross Plant[1]	Net Salvage Rates Proposed[2]	Net Salvage Rates 0% Inflation[3]	Difference in Future NS	Remaining Life[4]	Change in Accruals
A	B	C	D	E=(C-D) x B	F	G=E/F
354	$95.4	-75%	-104%	$27.7	55.9	$0.5
355	$697.9	-90%	-90%	$0.0	60.0	$0.0
356	$242.5	-100%	-114%	$33.9	48.9	$0.7
364	$2,463.4	-263%	-180%	-$2,044.6	47.2	-$43.3
365	$1,433.0	-144%	-195%	$730.8	45.1	$16.2
366	$1,811.9	-38%	-108%	$1,268.3	45.8	$27.7
367	$5,551.4	-75%	-112%	$2,054.0	34.6	$59.4
368	$3,508.6	-25%	-27%	$70.2	22.5	$3.1
369	$1,301.4	-125%	-178%	$689.7	32.1	$21.5
Difference between SCE proposed net salvage and 0% Inflation net salvage						**$85.8**

1 - Workpapers to SCE-09, Vol. 03 Chapter I, II, III.B - Book A - page 3, Column D
2 - SCE-09, Vol. 03, page 9 - Table I-3, Column D
3 - SCE-09, Vol. 03, page 48 - Table II-16, Column C
4 - Workpapers to SCE-09, Vol. 03 Chapter I, II, III.B - Book A - page 8, Column 10

If the Commission were inclined to address the best way to incorporate inflation into the future cost of removal, TURN's analysis does not provide a sufficient record on which to base a decision. Mr. Dunkel indicated that he "did not dispute the SCE estimates of annual inflation rates or prepare any original estimate of future inflation,"[1674] but explained that he proposed a 20% "adder" to the recent average incurred costs to "easily cover" inflation in the recent past.[1675]

ALJ Wildgrube asked whether using a present value approach would cancel out the effects of inflation.[1676] In the past, TURN has proposed a net present value (NPV) method as a means to lower the

[1674] Exhibit SCE-25, Vol. 4, Appendix B, p. 27, Data Request SCE-TURN-014, Q. 6.
[1675] TURN, Dunkel, Tr. 18/2634.
[1676] ALJ Wildgrube, Tr. 17/2431.

annual accrual by stating the future cost of removal in present value terms.[1677] In this proceeding, however, TURN elected not to offer any written testimony at all on how such a computation would be done. The Commission rejected an NPV approach on a fuller record in at least one prior decision, reasoning that "SP U-4 understates future removal costs in nominal dollars," so introducing a "complex and controversial" net present value methodology was unnecessary.[1678]

Mr. Dunkel re-argues another TURN favorite, that SP U-4's use of the phrase "anticipated changes in labor costs for the immediate future" does not mandate the use of inflation in determining the future cost of removal.[1679] The Commission has already rejected this theory when a different TURN expert proposed it: "We find that TURN's interpretation of SP U-4 is not supported by the tables in SP U-4 which illustrate what was intended by this statement."[1680]

One final fundamental point about inflation requires underscoring: Because TURN's "incurred-versus-accrued" methodology defers expenses to future generations of customers, the *overall* total cost to customers will be higher, with or without inflation. That is because deferring depreciation expense keeps SCE's rate base higher for a longer period of time, which results in a higher revenue requirement owing to the associated return on rate base and taxes.[1681]

18.3. Life

SCE did not employ gradualism to temper the results of its life analysis, nor was SCE's life analysis subject to explicit compliance mandates from the 2015 GRC (as was the case for net salvage). There are three categories of assets where SCE's proposed average service lives are disputed[1682]—(1) T&D (Account 369), (2) hydroelectric (hydro) facilities; and (3) solar photovoltaic, discussed in the

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[1677] D.06-05-016, pp. 209-211.
[1678] D.07-03-044, p. 232.
[1679] Exhibit TURN-05, p. 35 ("However, instead of reflecting a reasonable projection of anticipated changes in labor cost or other inflation 'for the immediate future', SCE instead included many, many decades of projected future inflation in its proposed 'per unit' net salvage calculations.").
[1680] D.07-03-044, p. 228.
[1681] Exhibit SCE-25, Vol. 4, pp. 26 & 30-32.
[1682] SCE's life analyses for the following assets are undisputed: Generation Plant (except for hydro and solar), including Palo Verde, Pebbly Beach, Mountainview, Peakers, Fuel Cells, and Energy Storage); General Plant (389, 390, 391, 393, 394, 395, 397, 398); and Intangible (non-hydro 302 and 303). *See* Exhibit SCE-09, Vol. 3, p. 10, Table I-4 for life span proposals for Generation Plant, and Table I-5 for lives proposal for General and Intangible Plant.

subsections below. The resulting difference in proposed depreciation expense is $12.9 million, $16.2 million, and $5.5 million, respectively.[1683]

18.3.1. T&D Life

As discussed in the introduction to this chapter, SCE had sufficient data for its T&D accounts to perform (for the first time) an actuarial analysis to estimate life parameters. Dr. White performed an actuarial analysis of 18 T&D accounts.[1684] For 16 of the 18, SCE proposes estimated service lives that are the same or longer than what the Commission authorized in the 2015 GRC.[1685]

ORA does not oppose any of SCE's T&D life proposals; TURN opposes the estimated life of only Account 369, Services,[1686] though the evidence it cites is not credible. Thus, SCE recommends retaining the currently authorized average service life for that contested account.

A final Commission decision should adopt the following average service lives (ASLs) and survivor curves in the table below:

[1683] Exhibit SCE-25, Vol. 4, p. 2, Table I-1, Comparison of Depreciation Expense Proposals. Note that the differences between these dollar values and the ones in the Joint Comparison Exhibit (JCE) result from the JCE applying the parties' proposed NSRs using 2018 plant balances even though SCE's and TURN's testimony referred to 2015 plant balances.

[1684] Dr. White performed an actuarial life analysis of General Buildings Account 390, which is also undisputed. Actuarial life analyses were not performed for T&D land accounts 350.2 and 360.2.

[1685] If the inflation rate applied to forecast cost of removal were actually being litigated in this proceeding, the lengthening of service lives would logically lead to increased cost of removal stemming solely from the inevitable results of inflation. As described in Section 18.2.7, however, SCE's moderated proposal produces results equivalent to assuming inflation at less than zero percent.

[1686] The "Services" account includes all sizes and types of service conductors that provide secondary voltage service to customers. Each service, from the point of connection with an underground structure or the line conductor on a pole, to the point of connection with the customer's facilities, including services installed in conduit on a building wall, is a retirement unit reported by the number of conductors comprising the service. Exhibit SCE-25, Vol. 4, Appendix B, p. 5, Data Request TURN-SCE-032, Q. 11.c. (CPR Accounting Instructions attachment to TURN-SCE-032 Q. 11.c.).

FERC Account	Description	2015 GRC Authorized	SCE Proposed[1]	Change in Life (yrs)
Transmission Plant				
350.2	Easements	60	60	
352	Structures and Improvements	55 S3.0	55 L1.0	
353	Station Equipment	45 R0.5	40 L0.5	*-5*
354	Towers and Fixtures	65 R5.0	65 R5.0	
355	Poles and Fixtures	50 R0.5	65 SC	*15*
356	Overhead Conductors & Devices	61 R3.0	61 R3.0	
357	Underground Conduit	55 R3.0	55 R3.0	
358	Underground Conductors & Devices	40 R2.5	45 S1.0	*5*
359	Roads and Trails	60 SQ	60 R5.0	
Distribution Plant				
360.2	Easements	60	60	
361	Structures and Improvements	42 R2.5	50 L0.5	*8*
362	Station Equipment	45 R1.5	65 L0.5	*20*
364	Poles, Towers and Fixtures	47 L0.5	55 R1.0	*8*
365	Overhead Conductors & Devices	45 R0.5	55 R0.5	*10*
366	Underground Conduit	59 R3.0	59 R3.0	
367	Underground Conductors & Devices	45 R0.5	43 R1.5	*-2*
368	Line Transformers	33 R1.0	33 S1.5	
369	Services	45 R1.5	45 R1.5	
370	Meters	20 R3.0	20 R3.0	
373	Street Lighting & Signal Systems	40 L0.5	48 L1.0	*8*
General Buildings				
390	Structures and Improvements	38 R3.0	45 R0.5	*7*

1) Exhibit SCE-09 Vol. 3, p. 9, Table I-3 Summary of SCE's Request for Depreciation Parameters

For Account 369, SCE proposes to retain the average service life of 45 years using the R1.5 curve notwithstanding that the Company's actuarial data (covering the years 2002-2015) produces a result suggesting an estimated average service life of 65 years. The reason for SCE's reluctance to rely on the output of its study is because for this account, unlike the other T&D accounts Dr. White analyzed, SCE changed its on-the-ground investment in a way that may have produced discrepancies in retirement data. Specifically, SCE changed from investing in three-phase bare-wire conductor (three distinct units of property) to primarily triplex (which is a sheathed, inseparable conductor) without changing its asset catalogue. To account for triplex as three units of property (for an apples to apples comparison with how this asset had been recorded previously), SCE made modifications to its accounting systems that may

have had been implemented unevenly, which has some bearing on the accuracy of SCE's retirement data on which Dr. White's actuarial analysis relied.[1687]

Because of the inconclusive results, SCE proposes to retain the 2015 GRC's authorized service life, which was more conservative (*i.e.*, yielded a longer estimated life) than what SCE had proposed in that proceeding.[1688] In the 2015 GRC, the parties and the Commission relied on SPR data, not actuarial data, and the Commission found that from its "review of the SPR data, we note that the R1.5 curve suggest[s] a 44.5-year life [.]" The Commission's prior conclusion is a reasonable basis to adopt a 45-year service life.

With one skewed graph and a few lines of text—but no analysis—Mr. Dunkel proposes to lengthen the authorized/proposed life for Account 369 by 10 years, to 55 years. The difference in the parties' proposal amounts to $12.9 million of forecast depreciation expense.[1689] Mr. Dunkel claims that his recommendation is more consistent with SCE's actuarial data for a more recent period (2009-2015) than the one SCE used (2002-2015).[1690] But as Dr. White testified, any problems with the 2002-2008 data for this account would be carried over into the 2009-2015 vintage data, so TURN's use of the narrower observation band does not produce more accurate results.[1691]

Even if it did, TURN's proposal "is based on nothing more than a visual comparison of two survivor curves plotted on the same graph" (*i.e.*, SCE's proposed curve and TURN's proposed curve), compared with two observation bands from different time periods (2002-2015 and 2009-2015).[1692] Visual curve fitting is a rudimentary analysis, "employed long before the advent of computers" and is not a statistical method of life analysis.[1693] Even the scaling of the visual graph in Mr. Dunkel's Chart 3[1694] was inexplicably skewed, with the Y axis (i.e., percent surviving) being compressed, and the X axis (*i.e.*, age in years) being extended. Although this might lead to Mr. Dunkel's desired result—a longer life than currently authorized—the cursory conclusions are based on a distorted graph that, in Dr. White's expert opinion, "flattens the appearance of the plotted proportions" and "narrows the visual

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[1687] Exhibit SCE-25, Vol. 4, pp. 57-58.
[1688] D.15-11-021, pp. 409-410.
[1689] Exhibit SCE-25, Vol. 4, p. 2, Table I-1, Comparison of Depreciation Expense Proposals.
[1690] Exhibit TURN-05, pp. 67-68.
[1691] Exhibit SCE-25, Vol. 4, p. 70.
[1692] Exhibit SCE-25, Vol. 4, p. 69.
[1693] Exhibit SCE-25, Vol. 4, p. 70.
[1694] Exhibit TURN-05, p. 67.

difference between the plotted proportions surviving[.]"[1695] When Dr. White fixed the scaling on Mr. Dunkel's graphs, the difference between SCE's proposed curve and TURN's—relative to the plotted actuarial data—hardly leads to a conclusion that a 55-R.15 curve is a better fit than a 45-R1.5.[1696] To underscore the point that neither SCE's actuarial analysis nor Mr. Dunkel's visual curve-fitting analysis leads to a reasonable result relative to the currently authorized service life, Dr. White shows that a more proper curve-fitting analysis—if one relied on visual curve-fitting—would have an average service life of 109 years for Account 369, including some assets that would remain in service for an unrealistic 327 years.[1697]

In light of the data problems SCE identified, that are isolated to this account—and the unreliable testimony from Mr. Dunkel that uses a skewed visual plotting analysis that, even if performed correctly, would yield implausible results—the Commission should simply retain the currently authorized service life because it is based on the Commission's assessment of SPR data from the 2015 GRC. For the 2021 GRC, SCE expects to interrogate the data for this account more closely to reach a more accurate result than what it and TURN produced here.

18.3.2. Hydro Life

For hydro generation assets, TURN asks the Commission to upend the methodology proposed and used by SCE without dispute for more than ten years. Pursuant to this methodology, SCE sets the depreciable life of hydroelectric facilities at a period equal to the average remaining years on the facilities' current FERC licenses except for facilities with expired licenses or with license expiration dates within five years of the date on which SCE filed its application. For only those facilities—i.e., the ones where SCE has commenced the relicensing process at FERC for expired or soon-to-be-expired licenses—the depreciable life is assumed to be extended by forty years to approximate the anticipated license renewal period. For the balance of facilities, which are outside the five-year window, no renewal is assumed.[1698]

[1695] SCE-25, Vol. 4, pp. 70-71.
[1696] SCE-25, Vol. 4, p. 72.
[1697] SCE-25, Vol. 4, p. 73.
[1698] SCE is not assuming that the licenses with more than five years remaining will not be renewed; rather, consistent with past practice, SCE proposes to set the depreciable lives of the hydro facilities equal to the remaining life on the licenses. This is a fair and reasonable depreciation assumption that allows SCE to recover the costs of assets that may not survive to the ultimate decommissioning of the hydro facilities.

By contrast, TURN assumes 40-year license renewals for all facilities within five years of license expiration (same as SCE), but adds more than three decades to the license expiration dates of facilities with current licenses that are within 6-15 years of expiration. When asked under cross examination whether he had prepared testimony or workpapers to support the proposed 15-year cut-off date, Mr. Dunkel said "I don't know if that's in the workpapers . . . There was some judgmental break point we had to use."[1699] But Mr. Dunkel's judgment involved analysis no more sophisticated than Goldilocks'. When asked why he chose 15 years and not, for example, 10 years, he responded only that "[t]en's not very far into the future. It's a judgment but that, I think, was a reasonable judgment."[1700]

The hydro facilities falling between 6-15 years of retirement happen to be among SCE's smallest and potentially most uneconomic to operate. To determine the number of years to tack onto the end of those facilities' licenses, Mr. Dunkel assumed that the percentage of SCE's hydro facilities decommissioned in one isolated ten-year period (16% in 2000 to 2010) is an appropriate indicator of the percentage of hydro facilities that will retire in the future. Again, he offered no testimony explaining why that period was relevant for facilities that can be over one hundred years old. He then proposed to set the depreciable lives of these facilities at 33.7 years longer than their current license expiration dates (84% probability of license renewal times 40-year license periods=33.7 years). Leaving aside the arbitrariness of having applied his methodology to facilities within 15 years of license expiration, Mr. Dunkel's assumption about the probability of retirement is far too optimistic. SCE's industry comparison showed probabilities of decommissioning in the range of 30-40%, not 16%.[1701] Specifically, in rebuttal, SCE showed that most of the 19 powerhouses Mr. Dunkel studied in the 2000-2010 period included the largest MW powerhouses in SCE's hydroelectric fleet, averaging over 110 MWs each and totaling about 84% of the total hydro nameplate capacity. These large powerhouses had much stronger economics than the 13 powerhouses at the heart of SCE's dispute with TURN on this issue. The 13 with licenses expiring 6-15 years from the date of SCE's application are more susceptible to retirement than the large hydro plants on which Mr. Dunkel based his probabilistic proposal.[1702]

[1699] TURN, Dunkel, Tr. 18/2565.
[1700] TURN, Dunkel, Tr. 18/2565.
[1701] Exhibit SCE-25, Vol. 4, p. 52 & Appendix D. The study covered hydro industry retirement trends, concluding that between 2005 and 2014, 30% of the 1,396 hydro generating units had been retired. More significantly, the study found that smaller, older generating units such as the ones at issue in this proceeding were more likely to be retired than newer, larger units.
[1702] Exhibit SCE-25, Vol. 4, pp. 51-52.

The difference between SCE's proposal and TURN's amounts to $16 million of depreciation expense annually. If Mr. Dunkel had selected a different number of years-to-expiration, like 10 instead of 15, that difference between the parties would be halved. SCE's proposal is more sensible for a number of reasons.

First, assuming license renewal for facilities within the relicensing window period comports with the federal regulation requiring that notices of intent (NOIs) for license renewals be filed no earlier than five and one-half years of license expiration.[1703] TURN's 15-year cut-off has no justification other than Mr. Dunkel's vague reliance on his unsubstantiated "judgment." He testified that he was unaware of FERC's NOI deadline yet inexplicably dismissed the importance of that deadline, claiming it "doesn't really affect my testimony."[1704]

Second, the logic underlying TURN's proposal is that the final decommissioning date should be the period over which to allocate the capital costs of assets used at the hydro facilities. But this would cause an unreasonably long recovery period that would fail to allocate costs over the useful life of the actual assets at each hydro facility. A good analogy is to substations, which, like hydro facilities, can provide continuous service for over 100 years, even though the depreciation lives of the assets *within* the substation (*i.e.*, transformers, circuit breakers, and other equipment) will continually require replacement over a reasonable time period. That reasonable time period is not 100 years; rather, the Commission has authorized depreciable lives of substation equipment ranging between 25-45 years, the expected-time-to-wear-out for the substations' component parts. Similarly, for hydro facilities, the Commission authorized allocation of hydro assets over the life of the current licenses. That is reasonable, because while hydro facilities are long-lived, the assets within them will require continuous refurbishing, rebuilding, and replacement of component parts over that time.[1705]

Third, license renewal—especially for small hydro facilities—is unpredictable, not a "given." For example, SCE's Borel powerhouse was relicensed in 2006, but notwithstanding a 40-year license, circumstances have changed so dramatically that it has been out of service since June 2013 due to

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[1703] *See* 18 C.F.R. § 5.5(d), "*When to notify*. An existing licensee or non-licensee potential applicant must notify the [Federal Energy Regulatory] Commission as required in paragraph (b) of this section [governing the notification of intent] at least five years, but not more than five and one-half years, before the existing license expires."

[1704] TURN, Dunkel, Tr. 18/2565.

[1705] Exhibit SCE-25, Vol. 4, p. 48.

ongoing seismic restrictions affecting the US Corp of Engineering Lake Isabella Reservoir dam.[1706] The economics of small hydro facilities are generally uncertain, leading to 30-40% decommissioning rates for IOU hydro facilities nationally.[1707] As just one example, *after* SCE filed its application, it determined that one of its hydro facilities (Rush Creek) outside the five-year relicensing window will be partially decommissioned because the estimated cost to upgrade the aging dam for the Agnew reservoir (to address seismic risks) would be uneconomic for SCE and its customers.[1708] The rest of the assets at the same Rush Creek powerhouse are also at risk of being decommissioned.[1709] But under TURN's probabilistic proposal, the life would be extended 33.7 years, to the year 2060, based on no facts justifying that outcome. Indeed, TURN's proposal results in a hydro depreciation rate of 2.13%, well below the industry average of 3.21%. SCE's proposed rate is 3.57%.[1710]

Finally, there is an important risk to TURN's life-lengthening proposal for SCE's hydro facilities. If, as in the case of Rush Creek, TURN overshoots the average expected service life of these facilities, two required results will ensue in SCE's next GRC. First, the depreciable life will be reduced, meaning that the remaining investment will be accelerated and collected over a shorter number of years. Second, retirement of the asset will trigger decommissioning, which can cost hundreds of millions of dollars and has not yet begun being collected for small hydro facilities.[1711] Thus, it is more prudent for the Commission to set the lives of these precarious facilities consistent with their current license expiration dates, rather than elongate them only to suffer the abrupt consequences of saddling customers with compounded increases to depreciation expense resulting from (a) decommissioning, and (b) recovery of the remaining original cost over a shorter period of time.

18.3.3. Solar Life

TURN joins ORA in seeking to retain the 25-year average service life of SCE's solar PV assets, largely in reliance on manufacturer warranty periods covering a guaranteed percentage of solar output.

[1706] Exhibit SCE-25, Vol. 4, p. 51. If Mr. Dunkel counted Borel in the list of powerhouses he studied in the 2000-2010 time period, and *excluded* the large powerhouses that are not comparable to the 19 small hydro facilities at issue in this proceeding, the percentage of retirements would jump from 30 percent to 40 percent, far from the 16% on which Mr. Dunkel's proposal is based. *Id*.

[1707] Exhibit SCE-25, Vol. 4, p. 52 & Appendix D.

[1708] Exhibit SCE-25, Vol. 4, p. 53.

[1709] *Id.*

[1710] Exhibit SCE-25, Vol. 4, p. 47, fn. 107.

[1711] Exhibit SCE-25, Vol. 4, p. 49, lines 16-19.

SCE instead seeks to reduce the period by five years, to a 20-year life, consistent with what the Commission determined in the 2012 GRC. The reason is simple but compelling. Even if manufacturer warranties for the panels are 25 years, the panels will likely be removed and retired a few years earlier given that the crowded and structurally weak warehouse rooftops on which the panels are mounted *themselves* have a life span of twenty years.[1712] The roof life, which matches the lease life, is a force of retirement that is, of course, not covered by the terms of the warranties.[1713]

Mr. Dunkel minimized the impact of the twenty-year roof-life, speculating that SCE could simply renegotiate its lease[1714] (even though the lease terms contemplate renewal under only one circumstance controlled by the landlord[1715]) or, failing that, convince the landlord to keep the majority of panels on the crowded rooftop while "the building owner's workers . . . reroof the cleared section, then move the panels from the next section onto the newly reroofed section" little by little.[1716] Mr. Dunkel admitted that he did not prepare a cost-effectiveness analysis to see whether such an approach would be justified for SCE's ratepayers,[1717] insisting without any basis that his proposal is a "very reasonable and practical solution."[1718]

Mr. Varvis, by contrast, did consider the costs and benefits of removing and re-installing the panels upon roof replacement. He testified that to uninstall and re-install the aging panels would cost approximately $64 million in O&M (not counting re-installation costs) and then, a few years later, decommissioning expense totaling another $81 million.[1719] Weighing these costs, Mr. Varvis concluded that "SCE would probably retire the assets from service [when the roof is replaced] because the incremental benefits of the lease extension may not be large enough to overcome the expenses to remove and re-install the aging equipment."[1720]

[1712] Exhibit SCE-25, Vol. 4, p. 44.

[1713] *See* Exhibit SCE-100, Solar Facilities Rooftop Lease for Ontario Airport Building 2, p. 54, Schedule D, Rooftop Report prepared by Independent Roofing Consultants, p. 9 ("The roof system on this building was constructed per industry standards meeting a 20-year potential service life.").

[1714] Exhibit TURN-05, p. 63.

[1715] Specifically, if the *landlord* determines, during the pendency of the 20-year lease, that more than fifty percent of the solar panels need to be removed for an impending roof replacement, then SCE at that time could seek a 20-year renewal. Exhibit SCE-100, p.13.

[1716] Exhibit TURN-05, p. 65.

[1717] TURN, Dunkel, Tr. 17/2552.

[1718] *Id*.

[1719] Exhibit SCE-25, Vol. 4, p. 45, and WPSCE-25, Vol. 4, pp. 166-167.

[1720] Exhibit SCE-25, Vol. 4, pp. 44-45.

Apart from the rooftop life, there are other forces of retirement that counter the simplistic view that the average service life of the panels should match their warranty lives, and these forces include equipment failure, theft/vandalism and natural disasters. ORA seeks to keep SCE's adopted average service life at 25 years to "be consistent in line with the assumptions regarding the life and retirements of solar PVs in different proceedings."[1721] However, this proposal is not appropriate because SCE is the only California IOU with solar rooftop installations, as opposed to ground-mounted ones.[1722] The lease life is critically important to SCE's adopted average service life.[1723]

18.4. Generation Decommissioning

Decommissioning costs represent the cost to permanently retire a generation station at the end of its depreciable life, the expected year of final retirement. As such, SCE proposes to retain its currently authorized approach of escalating the estimated decommissioning costs to the year of final retirement. TURN proposes to restate SCE's decommissioning costs by eliminating escalation beyond 2020.[1724] The Commission did not adopt TURN's proposal to eliminate all future escalation of costs for generation decommissioning in SCE's last rate case[1725] and should not adopt TURN's proposal to eliminate escalation beyond 2020 in this rate case. TURN's proposal is not consistent with SP U-4 because it does not evenly allocate costs over the life of the assets and instead, it would have customers pay more by deferring costs. Adopting TURN's proposal for Mountainview alone would defer $0.3 million of 2018 depreciation expense[1726] to future customers and would increase total revenue requirement to customers by $5 million over the life of the plant.[1727] Adopting this proposal for all generation stations, including Peakers and Solar PV facilities, will increase the revenue requirement charged to customers by even more.

[1721] Exhibit ORA-19C, p. 11.
[1722] Exhibit SCE-25, Vol. 4, p. 46.
[1723] ORA's reliance on the manufacturers' warranty is also misplaced. It does not cover a contingency like roof replacement. Exhibit SCE-25, Vol. 4, pp. 45-46.
[1724] Exhibit TURN-05, p. 58, fn. 98-99.
[1725] The issue of applying inflation to decommissioning costs was not addressed in D.15-11-021, but the Commission adopted SCE's proposal—which included inflation to the year of final retirement—over TURN's proposal to eliminate it entirely. Exhibit SCE-25, Vol. 4, p. 40.
[1726] Exhibit SCE-25, Vol. 4, p. 40, Table III-10, line 1.
[1727] Exhibit SCE-25, Vol. 4, p. 42.

18.5. Depreciation Study – Additional Issues

18.5.1. SCE's Thoughtful Application Of Gradualism Balances Cost-of-Service Ratemaking With A Concern For Customer Rate Impacts, And Is Consistent With Past Commission Precedent

SCE's per-unit analysis confirmed that for the Company's largest T&D plant accounts, the future cost of removal is substantial. Even assuming a zero percent inflation rate, which is unrealistic, the annual accruals required to spread the total cost of removal over the average remaining life of these assets is $170 million per year more than what is currently authorized, and $86 million more than SCE is requesting in this rate case.[1728] The "fully loaded" estimate, assuming a reasonable 2.72% inflation rate, is $976 million per year. Though reasonable minds may differ about the appropriate inflation rate to apply, that general figure at least attempts to answer the *first* question required of any depreciation study—what is the total future cost of removal, allocated evenly over the remaining life of the assets? The substantial figure corroborated the trend about which SCE's witnesses have been testifying for several rate cases, namely, that various cost pressures are being brought to bear on SCE's removal activities, including SCE's increasingly urban service territory, increasing labor and contractor rates, increased permitting costs, more stringent environmental regulations, disposal fees, and system complexity.[1729] The difference is that this time, the perceived infirmities in SCE's prior analyses—lack of substantiation of expert judgment, assumptions about the future retirement mix automatically mimicking the experience of the past, disputes over whether past inflation will continue at the same rate in the future—were neutralized by the very design of the study. *That* is the significance of the study, even if its translation into requested depreciation expense will not materialize all at once in this GRC.

When increasing cost pressures are paired with the effects of prior Commission decisions adopting conservative net salvage rates for a variety of reasons, the "catch-up" required to assign the total cost of removal evenly year-over-year to the proper generation of customers can appear daunting. The Commission has recognized that trying to remedy accumulated deficiencies by subjecting current ratepayers to significantly higher rates is unfair.[1730]

[1728] The $170 million is equal to SCE's pending proposal for T&D Net Salvage of $84 million (*See* Section 18) and the $86 million of unrequested net salvage accruals resulting from Net Salvage Rates assuming 0% inflation (*See* Section 18.2.7).

[1729] Exhibit SCE-09, Vol. 3, p. 33.

[1730] D.14-08-032, p. 599.

Hence, the second question—who should pay for the future cost of removal? TURN's expert melded the first question with the second, aiming for a palatable accrual proposal without identifying what the total future cost of removal is likely to be. His approach will only delay consideration of the issue to future customers and future Commissioners, leaving the proper policy approaches uninformed and undeveloped. In fact, when ALJ Wildgrube asked Mr. Dunkel for his expert opinion on whether it would be appropriate to apply gradualism to collect less than what the results of a sound study would produce, he put off the question to the Commission. The ALJ persisted, "Do *you* have any opinion as [to] whether it would be an appropriate course of action" to apply gradualism? Mr. Dunkel responded, "That is not really my function," and admitted it was beyond his area of expertise.[1731]

SCE, on the other hand, gave the issue careful thought, in part by relying on Commission precedent for gradualism. As indicated in the policy section at the beginning of this brief, SCE concluded that it would be unreasonable to burden customers in this rate case cycle with redressing the depreciation reserve deficit that has mounted over several years, particularly given competing imperatives to begin modernizing the grid and replacing SCE's aging infrastructure *now*.

The Commission has recognized the need to balance the costs of providing safe, reliable, clean electricity, against the equally important need to avoid customer bill shocks. In the depreciation context specifically, it has adopted a principle of "gradualism," the idea of which is to spread the increases in depreciation expense over time to mitigate the immediate rate impact on customers.

Tempering a future cost of removal estimate has practical appeal as well. Errors are inherent in any forecast of removal costs that will not be incurred until well into the future. The Commission recognized this, too, warning that one must "be cautious in making large changes in estimates of . . . net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect."[1732] Indeed, the premise of SCE's per-unit analysis is that one can take the per-unit historical cost to remove assets, and apply that per-unit cost to the quantities of assets in the surviving plant balance to obtain a reasonable forecast of the cost to remove the assets given projections about the timing of the assets' retirements. A key assumption in this analysis is the per-unit cost to retire each asset. While the proposals presented in SCE's depreciation study substantiate sound estimates of the future costs to retire, SCE does not overlook that future rate cases will provide updates to SCE's

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[1731] TURN, Dunkel. Tr. 18/2629-30.
[1732] D.14-08-032, p. 598.

recorded experience that will further refine the expectations of future net salvage. By moderating SCE's depreciation rates, the Commission will make progress towards SCE's current estimate of forecast net salvage while permitting the Company in future rate cases to rely on additional data to refine its forecasts.

The Commission also has recognized that setting net salvage parameters "is not a precise science, and experts can differ in applying judgment in estimating these parameters."[1733] However, it authorized lower-than-requested net salvage rates by relying, in part, on public policy concerns about the impact on current customers' retail rates, not on the science and judgment of experts.[1734]

SCE acknowledges that the decision to collect less from today's customers than what its study suggests does result in cost deferral. The Commission, too, has acknowledged that applying gradualism "involves inter-temporal equity trade-offs between current and future customers," but nonetheless concluded in a relatively recent PG&E rate case that "[t]hese inter-temporal equity issues must be weighed in relation to overall cost increases imposed on customers in each GRC cycle."[1735] The Commission's considerations in that case are equally valid here for SCE: "In view of the many new programs being implemented in this GRC, overall cost increases at issue in this GRC relative to past GRCs are substantial."[1736] In any event, applying gradualism in one GRC cycle does not mean indefinite suspension of inter-generational equity enshrined in Standard Practice U-4: "Depending on conditions prevailing in future GRC cycles, ratepayers may be better positioned to absorb removal cost increases in comparison to today's customers."[1737]

Although any forecast of cost of removal is an approximation of the costs that will actually be incurred, it is important to make meaningful steps towards equitable cost recovery. In PG&E's case, though the Commission found it "appropriate to moderate the further increased burden imposed in this GRC relating to growing negative salvage costs," it still saw the importance of "providing measured recognition in current rates of increasing cost trends."[1738] Therefore, given the consciously moderate

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[1733] *Id.*, p. 596 & Finding of Fact (FOF) 286 at p. 716.

[1734] Another recent Commission application of the "gradualism" principle occurred in the rate design context. In D.15-07-001, which adopted reforms to the residential tiered rate structure, the Commission determined that "[t]o minimize the rate shock, the transition from the current four-tiered rates must be gradual." D.15-07-001, FOF 78 at p. 315.

[1735] D.14-08-032, p. 599.

[1736] *Id.*

[1737] D.14-08-032, p. 600.

[1738] D.14-08-032, p. 602.

extent of SCE's proposed incremental increase of $71 million (applied to 2015 plant balances), the Commission should strive to approve *at least* that much depreciation expense regardless of isolated conclusions it may reach on disputed depreciation issues (for example, the disputes about estimated life parameters discussed in Section 18.3).[1739]

18.5.2. While The Purpose of Collecting Depreciation Is Not To Fund Operations, Doing So Is An Ancillary Benefit To Ratepayers

At evidentiary hearings, the ALJs expressed interest in better understanding why and how SCE and other utilities use depreciation expense to fund capital investment and day-to-day operations given that it is not "sequestered" in a fund the way nuclear decommissioning expense is. Dr. White testified that while depreciation accounting has its own objectives—namely, timely recovery of the capital investment fronted by SCE's investors—it is "also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions."[1740] Using money collected from customers for depreciation expense to finance the utility's capital investment and other objectives reduces the marginal cost of external financing.[1741]

ALJ Roscow sought an explanation for why depreciation expense, once collected via a revenue requirement, is not used "to repay the investor directly"—rather than be reinvested in the Company.[1742] The answer has many parts. First, depreciation expense collected from customers via a revenue requirement is placed into a corporate pool of funds that, once comingled, is fungible and can be used for a variety of purposes.[1743] What is "charged to operations" gets recorded in accounts subject to scrutiny from auditors and from intervenors in subsequent GRCs who evaluate SCE's "recorded" numbers against what is being proposed in the case. The disposition of dollars is not "traceable" dollar-for-dollar to certain activities. Second, ratepayers would not benefit from sequestering depreciation

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[1739] One way to ensure that the Commission approves the full $71 million incremental request is by relying on accounts for which TURN's expert actually proposed more negative NSRs than SCE's moderated proposals (but still lower than what SCE's untempered study results show). Examples include accounts 355, 357, 359, 366, 368, and 373. *See* Exhibit SCE-25, Vol. 4, p. 7, Table II-2.

[1740] Exhibit SCE-09, Vol. 3, pp. 37-39.

[1741] *Id*.

[1742] ALJ Roscow, Tr. 17/2443-2444.

[1743] TURN's counsel confirmed this view. "[M]y understanding is that once depreciation expense is collected by Edison, that the company can do as it sees [fit] with it… It is fungible in terms of being a revenue stream that can be used for whatever purpose Edison wants to put it to . . . I don't know that there is anything that compels depreciation expense be used specifically for" capital investment. TURN, Finkelstein, Tr. 16/2358.

expense in the same way as nuclear decommissioning funds because that would increase the marginal cost of external financing, which would lead to increased rates for customers.[1744] As Dr. White explained, it is preferable to use internally-generated funds (like depreciation expense, deferred income taxes and retained earnings), at the weighted average cost of capital, than to raise funds at the *marginal* cost of capital.[1745] Third, if the utility were not growing, and the objective was to use depreciation expense to immediately repay investors for the cash they fronted to purchase a small number of assets, the single-asset example ALJ Roscow used[1746] would be applicable. In SCE's case, however, the utility continues to grow and investments in assets is ongoing. For that reason, promptly paying back investors only to turn around and raise funds is not necessary or advisable. As Mr. Worden testified, "if we were hypothetically to set aside [depreciation expense collected] in the checking account . . . we would have to go into the capital markets and borrow $4 billion per year. That would put a strain on our financing capacity and put a strain on the regulated capital structure."[1747]

Although SCE's accumulated depreciation reserve is not a "cash reserve" or "pot" of funds into which net salvage is "deposited" and cost of removal is "taken out,"[1748] it serves an important purpose to record accruals[1749] so that (a) the utility does not double-collect for the same purpose; (b) SCE's rate base is appropriately offset by depreciation it has collected. On the first point—making sure that what customers have already paid is used for that purpose at the appropriate time, instead of misused by the utility—a helpful resource not mentioned at evidentiary hearings is the decision in SCE's 2006 GRC, D.06-05-016, in which TURN successfully requested that the funds SCE collected for cost of removal

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[1744] SCE, White, Tr. 17/2446.

[1745] SCE, White, Tr. 17/2446-47.

[1746] ALJ Roscow, Tr. 15/2155.

[1747] SCE, Worden, Tr. 16/2349. As a related matter, the timing of depreciation expense recovery does not coincide with the repayment of bond principal to debtholders when bonds mature. *See* SCE, Worden, Tr. 16/2350.

[1748] In that respect, it is not accurate that accumulated depreciation is an "actual reserve" with "real money set aside in an account." ALJ Roscow, Tr. 18/2615. Rather, as Mr. Dunkel described, "[T]his reserve is a bookkeeping entry that . . . tells us how much we've actually collected from the ratepayers in the past through depreciation accruals that hasn't been spent [yet] for the intended purpose, which is to cover retirement and cover cost of removal. But they [the utility] don't take the money and put it in a bank account. While it's there, waiting to be used for its intended purpose, . . . it can be used for any purpose the company wants to us it for." TURN, Dunkel, Tr. 18/2616.

[1749] As SCE Witness Mr. Worden testified, by Internal Revenue Service and Securities and Exchange Commission regulations, SCE must keep its books through accrual accounting, which recognizes expenses when they are incurred, not when money changes hands. SCE, Worden, Tr. 16/2348.

be "recognized as a regulatory liability." That means that if the funds collected are not eventually spent on cost of removal, the Commission's options will be to mandate "a refund through future rate reductions or payment of future costs with no corresponding effect on future rates."[1750] The Commission reasoned that this was an appropriate course of action "when considering the magnitude of the asset balance that has accumulated, and which will be increased in the future, with ratepayer funding."[1751]

The same result was achieved in PG&E's decision in 2007. There, TURN similarly advocated that the utility be required to record a regulatory liability for pre-funded removal costs that it had already collected in rates to pay for future removal activities, arguing that such a requirement "will help to ensure that PG&E either uses the [billions of dollars] for its intended purpose or returns these funds to ratepayers."[1752] The Commission agreed, and mandated that PG&E (like SCE) classify pre-funded removal costs as a regulatory liability for ratemaking purposes. The Commission reasoned that doing so would "provide[] an extra measure of assurance that [the utility] will only use the amounts that it collects to pre-fund removal costs for their intended purpose" given that the "stakes [are] so high and the actual incurrence of the removal costs [so] far in the future."[1753] PG&E and SCE continue to record unspent cost of removal collections as a "regulatory liability," making "explicit the obligation to either spend the funds on costs of removal or return the balance to ratepayers."[1754] This is a consumer protection measure that continues today.

Thus, there is a three-fold answer in response to a question a customer might pose about where the portion of its rates owing to depreciation expense is "going." First and most important, the purpose of charging depreciation expense is to recover the cost of long-lived assets that are not consumed in a single year. Once collected, the money is available to pay back the cost of capital investments that investors "fronted" on behalf of customers in the past. A second purpose of the money is to fund the

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[1750] D.06-05-016, pp. 204-205.

[1751] *Id.*, p. 205. SCE had argued in the 2006 GRC (ultimately unsuccessfully) that it was unnecessary and redundant to formalize the "regulatory liability" given the many examples in which SCE had already refunded to customers costs of removal expenses that ultimately did not materialize. As an example of why SCE argued "there was never a risk of [it] 'disappearing' with ratepayer monies," SCE cited the example of plant divestitures that took place in 1998 as a result of industry restructuring. The purchasers of assets formerly owned by SCE assumed responsibility for decommissioning. Thus, the Commission had ordered SCE to refund to ratepayers the full amount of accumulated depreciation through the gain/loss calculation, including those amounts collected for plant decommissioning. D.06-05-016, pp. 198-199.

[1752] D.07-03-044, p. 214.

[1753] D.07-03-044, p. 216.

[1754] D.06-05-016, p. 190.

future cost to remove assets that customers are benefiting from today. This is the net salvage cost. A healthy result of collecting the money for the first two purposes is that when the money is transmitted to the utility in the form of rates paid on electric bills, the utility *records* what it collects and then it is able to *use* the cash for internal funding for ongoing future investments. Using internal funding is cheaper than raising the same money in the markets. Moreover, on the off-chance that the money collected for depreciation expense is eventually *not* used for its intended purposes, the Commission has long put safeguards into place to make sure the money is returned to customers.

To summarize, the depreciation accrual is recorded on the utility's balance sheet, while the utility's cash flow statement shows depreciation expense as a source of cash (and capital expenditures as a use of cash).[1755] Capital expenditures include the cost of removal that is incurred in the current year. Future costs of removal will also be funded by internally-generated cash at the time that they are incurred, or will be financed by investors. The purpose of setting depreciation rates is to determine the correct accrual of revenues to recover the accrued cost of long-lived assets and the projected cost of removing those assets at the end of their useful lives. The job of financing those activities belongs to the utility.

19. RATE BASE – ADDITIONAL ISSUES

TURN seeks hundreds of millions of dollars' worth of permanent write-offs in four general areas. First, as discussed in Section 19.1, TURN argues that to the extent the Commission declined in prior decisions to approve full recovery of certain investments, the assets should continue to serve customers but without a penny of cost recovery for SCE. In this category, TURN includes SCE's investment of thousands of brand new poles in 2014-2015 to replace aged ones approximately 70 years old, and smaller-scale investments also disallowed in the 2012 and 2015 GRCs. TURN's permanent write-off proposals go beyond what the Commission intended to reach in those decisions, which covered rate recovery for the associated rate case cycle only. The remedy for the Commission's finding of imprudence for aged poles, like any other imprudence finding, calls for fact-specific approaches to put customers in no better or worse a position than had the imprudent actions not been taken. SCE's permanent write-off of the carrying costs in 2015-2017 for the aged pole expenditures above authorized is sufficient, as it amounted to more than 20 percent of the total investment-above-authorized *not* counting significant tax timing benefits SCE's customers already enjoyed (that would require unwinding

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[1755] SCE, Worden, Tr. 16/2353-55.

if TURN's extreme position prevails). Similarly, for the balance of disallowed investments challenged by TURN, recovering the net book value of the used and useful assets is consistent with Commission precedent and is fair to ratepayers.

Second, as discussed in Section 19.2, TURN argues that even when no findings of imprudence have been made—and when, in fact, the Commission has *approved* several safety and reliability infrastructure programs in prior rate cases—SCE should still be barred from recovering its remaining costs for used and useful assets if they exceeded the previously-authorized forecast. In TURN's view, even when no balancing account or memo account is in place to cap spending in a specific activity, SCE is required to submit testimony more detailed than what the Rate Case Plan and recent Commission decisions require before it can recover 2014-2015 capital spending-above-authorized. TURN's extreme request is inconsistent with the basic tenets of forecast ratemaking, and it attempts improperly to punish SCE for not using TURN's heightened standards for assessing the reasonableness of prior spending.

Third, as discussed in Section 19.3, TURN asks the Commission to apply a new rule midstream, barring any inter-cycle changes in capitalization policy until the test year of the next GRC—or else suffer the consequence that the capitalized portions of the assets be written off. TURN ignores SCE's legitimate need to timely implement proper changes to SCE's accounting practices whether that means changing O&M expense to capital, or vice versa.

Fourth, as discussed in Section 19.4, TURN asks for a multi-hundred million disallowance related to SCE's selection and use of the "SPIDA" computer software for SCE's new Pole-Loading Program (PLP). TURN's punitive disallowance proposal is based on a flawed hindsight-oriented review, and does not appropriately take into account SCE's prudent software selection process, and careful balancing of costs, operational realities, and safety risks for the crucial PLP. TURN's SPIDA proposal also ignores the reality that all poles—including the PLP poles that were removed before they absolutely had to be—eventually must be replaced. By not accounting for that reality, TURN's proposal, if adopted, would essentially sanction confiscation of shareholder-financed utility assets and require the utility to provide free service to customers.

19.1 Aged Poles (and Ratemaking Treatment of Other Prior Disallowances)[1756]

19.1.1. Aged Poles

Beginning in 2013 and lasting for two years thereafter, SCE implemented a program to systematically replace aged poles as a means to "ramp up" its operations to embark on an ambitious safety program following catastrophic fires. The program was aimed at increasing the Company's capacity to replace poles, including its internal processes and resources, and the capacity of its contractors. The poles were targeted for replacement based solely on their age (but well beyond the end of their book lives), in part because SCE's evidence showed that older poles had significantly higher failure rates. SCE did not undertake physical inspections of the aged poles it replaced. For that reason and others, in the 2015 GRC, TURN and ORA disputed the prudency of the program, including whether the costs of removing aged poles that may have had more years of life left in them outweighed the benefits.[1757]

In D.15-11-021, the Commission balanced the varying considerations. On the one hand, it found that a good portion of the aged pole replacements (all replacements in 2013 and more than half of replacements in 2014) served their stated purpose to "ramp-up" SCE's pole replacement rate "to minimize execution risk of the considerably higher volume of pole replacements it forecasts for the [pole-loading program]."[1758] The Commission also indicated "support [for] SCE's goal of reducing the risk of an in-service pole failure."[1759]

On the other hand, because the Commission declined to accept SCE's Pole Loading Program (PLP) forecast, it also concluded that a number of poles replaced went beyond what was needed to meet the "ramp-up" effort, indicating that SCE had not "demonstrated that the aged pole replacements are prudent, at the level requested."[1760]

In responding to some of the arguments SCE had set forth in support of full recovery of all dollars spent, the Commission held that "[t]he 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

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[1756] *See* Exhibit SCE-25, Vol. 3, pp. 6-12 (Mr. Worden sponsored testimony defending SCE's aged pole proposal).
[1757] Exhibit SCE-25, Vol. 3, p. 6.
[1758] D.15-11-021, p. 113.
[1759] D.15-11-021, p. 113.
[1760] D.15-11-021, p. 113.

be recovered from rates." The Commission reasoned that "[t]hat question turns on the prudency of the investment decision."[1761] By the time the final 2015 GRC decision was issued, SCE had already recorded $108 million in capital expenditures more than what the Commission authorized in that decision.[1762] In other words, SCE was not authorized to include the revenue requirement on that $108 million in customer rates for the years 2015-2017.

The chart below[1763] shows what was authorized in the 2015 GRC relative to what was spent, including during the nearly year-long gap between when evidentiary hearings concluded in the 2015 GRC (October 2014) and when a decision was issued (November 2015):

Aged Pole Forecast Quantities and Actual Capital Expenditures Compared to Authorized

Line No.	Item	2015 GRC 2013	2014	2015	Total
	Units				
1.	2015 GRC Forecast	9,000	14,500	1,898	25,398
2.	Actual	5,245	16,338	1,248	22,831
3.	Authorized	5,245	9,000	-	14,245
4.	Auth. Less Actual	-	(7,338)	(1,248)	(8,586)
	Capital Expenditures ($000s)				
5.	2015 GRC Forecast	$53,630	$184,189	$24,622	$262,441
6.	Actual	$53,630	$200,840	$20,948	$275,418
7.	Authorized	$53,630	$114,000	$0	$167,630
8.	Authorized Less Actual	$0	-$86,840	-$20,948	**-$107,788**

Without re-litigating the facts surrounding the aged pole program or revisiting the Commission's findings from the 2015 GRC, SCE proposes in *this* proceeding to begin recovering the remaining net book value of the replacement poles in its Test Year 2018 revenue requirement (and continuing over their remaining book lives). SCE's proposal thus recognizes and incorporates the Commission's forecast adjustment for the three-year period covered by the 2015 GRC, but at the same time recognizes that the new replacement poles will be used and useful to customers for decades to come—far longer than the prematurely removed poles would have lasted.

[1761] D.15-11-021, p. 113.
[1762] Exhibit SCE-09, Vol. 2, pp. 3-4.
[1763] Exhibit SCE-09, Vol. 2, p. 4.

TURN opposes SCE's proposal, reading into the 2015 GRC decision an unstated intention to forever preclude SCE from recovering *any* value for the used and useful poles installed above the quantities permitted in the 2015 GRC. The following sections demonstrate why TURN's proposal is not a reasonable interpretation of the 2015 GRC decision, in large part because it undervalues the extent of the revenue that SCE has already forgone owing to the Commission's imprudence finding. TURN's proposal would have the Commission treat the adjustment for aged pole replacements as it would an investment made *without any ratepayer benefit* over the next fifty years. As Mr. Worden testified, that violates the "used and useful" test of rate recovery and denies an indisputable fact, which is that the aged poles would not have lasted as long as the new poles will, providing decades of future value to ratepayers.[1764]

19.1.1.1. The 2015 GRC Decision Applied To 2015-2017 Rate Recovery Only

In the 2015 GRC, the Commission found error in SCE's aged pole estimate with respect to the level of replacements required to meet the pole-loading program's (PLP's) ramp-up objectives. The Commission did not conclude that the poles themselves had no inherent future value to customers, or that the poles replaced prematurely would never fail. Because the poles replaced existing poles, there was of course no finding that the number or location of the poles was inappropriate. Rather, the Commission's intent was to impose a disallowance that would recognize the timing difference between SCE's programmatic age-based replacements, on the one hand, and what the natural course of replacements would have been absent the aged pole program, on the other.[1765] Had the Commission intended TURN's extreme remedy, to remove from rate base the full capital spent on all aged pole replacements in 2015 and part of 2014, it would have stated so explicitly.[1766]

Under SCE's more reasonable interpretation of the Commission's disallowance, the cost recovery of the replacement poles would begin at a significantly discounted price in 2018 because that is

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[1764] Exhibit SCE-25, Vol. 3, p. 7.

[1765] *See* D.15-11-021, pp. 113-114 ("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.").

[1766] Without citing to prior Commission precedent, TURN's testimony assumes the opposite: "Absent a clear statement from the Commission that it intends to proceed differently, a capital expenditure disallowed in a prior decision must stay disallowed, period." Exhibit TURN-12, p. 3. This presumption is not reasonable given that rate cases cover a three-year period.

the first year in which the net book value of the new poles would begin to be recovered from customers' rates. TURN's proposal unreasonably assumes that the imprudence related to early replacement extends to the average life of the replacement poles, or 55 years,[1767] and relatedly assumes that customers are to receive free electric utility service from these poles to overcome the utility's ambitious safety initiative spanning an 18-month period. This unfair, punitive and unreasonable outcome should be rejected outright.

19.1.1.2. TURN Overlooks the Substantial Amount of Forgone Recovery Resulting From the Commission's 2015-2017 Disallowance

TURN calculates that under SCE's proposal for cost recovery of aged pole replacements, "an adopted disallowance of 36% of the utility's capital expenditures can transform into a disallowance of 1.5%[.]"[1768] TURN's math conflates two different concepts. The 36% refers to the proportion of SCE's *forecast* in the 2015 GRC not authorized by the Commission. That is not to be compared with the net book value SCE seeks to recover beginning in 2018 of the replacement poles placed in service that exceeded the authorized level. Rather, the issue before the Commission in the pending proceeding is whether SCE can begin recovering in 2018 the net book value of its recorded capital investment. The answer to this question should turn, in part, on quantifying the extent of the penalty SCE has already suffered—and which SCE is not re-litigating here.

By way of background, the Commission did not authorize inclusion in the 2015-2017 revenue requirement the amount of pole investment above the ramp-up level it found appropriate to meet the PLP's safety objectives. The present value revenue requirement (PVRR) of the $108 million that SCE spent above authorized is almost $110 million.[1769] But for the Commission's finding of imprudence, SCE would have collected this $110 million over the lives of the assets.[1770] However, accounting for the Commission's 2015 GRC decision, the remaining PVRR to be recovered from the investment under SCE's pending proposal beginning in 2018 is only $87 million. The difference between $110 million

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[1767] *See* Exhibit SCE-09, Vol. 3, p. 43.
[1768] Exhibit TURN-12, p. 3.
[1769] *See* Exhibit SCE-25, Vol. 3, Appendix A (which shows the PVRR calculation of the revenue stream had SCE obtained cost recovery in the 2015 GRC for the poles spent above authorized; the revenues forgone permanently; and the scope of SCE's pending proposal.).
[1770] The computation of this $110 million revenue stream assumes SCE spent within its overall authorized revenue requirement for the 2012 and 2015 GRC cycles.

and $87 million is $23 million, which equates to 21% of the revenue stream SCE otherwise would have gotten for the replacement poles not authorized. SCE has permanently forgone those revenues.[1771]

Mr. Worden testified that no one can know, today, how many more months or years sixty-five or seventy-year-old poles would have continued to provide service had SCE not replaced them under the Aged Pole program. If the question is whether SCE replaced too many poles based solely on their age even though they may have provided additional months or years of service, that answer has already been decided by the Commission. Contrary to TURN's testimony,[1772] SCE does not seek re-litigation of the merits of the program in this case. Was the Commission's disallowance of rate recovery over 2015-2017 for 8,586 replacement poles the precise remedy to compensate SCE's customers for premature investments? The answer to this question is unknowable, and actually was more than likely *not* known to the Commission when it rendered its decision because the 2014 and 2015 recorded numbers were not part of the evidentiary record.

TURN states, "By the Commission's calculation in D.15-11-021 based on the utility's forecasts, the amount disallowed was approximately $94 million."[1773] The more appropriate comparison is between what the utility *spent* versus what it was *authorized to spend*, which is $108 million (or $110 million on a PVRR basis).[1774] As Mr. Worden testified, the reduction in revenue recovery for the aged pole program can only be quantified with the benefit of the 2014 and 2015 recorded amounts, which were not mentioned in the 2015 GRC Decision and which had largely been spent before the Commission adopted its authorized forecast. TURN's disallowance calculation ignores recorded spend, but, in the same volume of testimony, insists on the Commission addressing the reasonableness of "SCE's **recorded 2014 and 2015** capital expenditures."[1775] TURN cannot have it both ways—basing SCE's cost recovery cap for aged poles on a percentage of the *authorized forecast* and at the same time seeking write-offs for spending *recorded* in years in which the Commission's authorized revenues had already been set.

[1771] Exhibit SCE-25, Vol. 3, p. 9.

[1772] Exhibit TURN-12, p. 3 ("Furthermore, it threatens to bog down an already challenging GRC process if the scope of the proceeding is expanded to include an opportunity for all parties to re-visit and re-argue disallowances adopted in past proceedings.").

[1773] Exhibit TURN-12, p. 4.

[1774] *See* Section 19.1.1., above, Table "Aged Pole Forecast Quantities and Actual Capital Expenditures Compared to Authorized."

[1775] Exhibit TURN-12, p. 13 (emphasis in original).

Looking back at the Commission's decision and the reasons why it concluded that only a "portion" of the pole forecast should be recovered from rates, Mr. Worden testified to his "high degree of confidence that the aged poles removed from service in 2014 and 2015 would not have lasted another 55 years, making TURN's permanent write-off proposal a far too harsh penalty, particularly for a program aimed at facilitating SCE's safety initiatives."[1776] He also reasoned that no one can reasonably disagree that making capital replacements *only* upon asset failure is not sensible, either from an economic or public policy/safety perspective. It is far more prudent from a customer perspective if a utility replaces assets at some reasonable date before they fail in service. Just as the decision to replace large numbers of poles beginning in 2014 required an estimate of how much service life remained, the remedy imposed on SCE by the Commission should consider the remaining service life of the original poles.[1777]

SCE has permanently forgone—in only three years—$22 million of revenue requirement for an investment of $110 million (PVRR). That is because the poles are capital additions recorded in FERC Account 364, which has a currently authorized depreciation rate of 7.04%. That rate is approximately double the average depreciation rate of all of SCE's other T&D assets. Rate base declines more quickly (*i.e.*, earlier) for this class of assets than it does for the average. Thus, because SCE has already forgone recovery for the disallowed poles in 2015-2017, it forever lost approximately 21% of its capital recovery early in the assets' lives.[1778]

When the Commission decided in the 2015 GRC to authorize 100% recovery of one portion of SCE's aged pole replacements, and no recovery of the rest, that decision automatically triggered a substantial amount of forever lost recovery just by operation of the three-year rate case. The Commission should adopt as reasonable SCE's proposal to recover the net book value of the long-lived used and useful assets.

19.1.2. Other Disallowances From the 2015 GRC Decision

TURN asserts that other used and useful assets should also be permanently removed from rate base, notably, the Westminster Labs and Energy Demonstration Evaluation Facility (EDEF), and the Pebbly Beach Automation Project, just because the Commission imposed a prior disallowance and did

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[1776] Exhibit SCE-25, Vol. 3, p. 10.
[1777] Exhibit SCE-25, Vol. 3, p. 10.
[1778] Exhibit SCE-25, Vol. 3, p. 11.

not explicitly invite SCE to seek recovery of the net book value in this GRC.[1779] SCE disagrees. Again, the difference is whether the Commission's prior disallowance was intended to bar recovery of the entire used and useful assets forever, or whether the disallowance is limited to the three-year rate case period.

The Commission's policy expressly contemplates SCE's cost recovery proposal. The Commission's Rate Case Plan (Standard Requirement List of Documentation Supporting an NOI) requires applicant utilities to clearly "identify"[1780] the previously disallowed items when requesting their rate recovery in a subsequent GRC. While the Rate Case Plan has undergone a number of amendments over the years, the Standard Requirement List has endured without revision, though the NOI has been eliminated. Therefore, the fact that the Commission "invited" SCE to shore up its cost-effectiveness showing for the CRAS project is not dispositive of whether—without such an explicit invitation—recovery is forever barred for the other disallowances in the 2015 GRC.[1781]

Mr. Worden's testimony offered at least two examples of prior Commission decisions that belie TURN's assumption that an explicit invitation is required before a utility can recover the net book value of investments disallowed in a prior GRC. Specifically, in SCE's 2009 GRC, the Commission rejected SCE's request to increase underground cable replacements in the years leading up to, and including, the test year. It slashed SCE's forecast from $10.5 million to $3.5 million per year, but by the time the 2009 GRC decision issued, SCE had already spent the capital necessary to replace the underground cable. In the 2012 GRC, SCE acknowledged having spent over $20 million above the authorized amount, and the Commission approved recovery of the net book value of those investments.[1782]

As another example, in the 2006 GRC, the Commission authorized $3.9 million for a new Catalina Administration Building (later known as the Station Office Betterment project). However, due to urgent system-wide needs stemming from customer and load growth, plus a heat storm in that period, SCE diverted capital from the Catalina project to fund these higher priorities. In the 2009 GRC decision, the Commission declined to adopt SCE's cost recovery proposal for the same administration building, but acknowledged that if SCE spent the money anyway, it could do so at the risk of not recovering its

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[1779] Exhibit TURN-12, pp. 8-13. SCE and TURN agree that the Corporate Media Center was properly written off consistent with Mr. Worden's testimony in Exhibit SCE-25, Vol. 3, p. 2.

[1780] D.07-07-004, Appendix A, pp. A-19-20, A-32, & "Standard Requirement List of Documentation Supporting An NOI," Paragraph 7.B.

[1781] Exhibit SCE-25, Vol. 3, p. 14.

[1782] Exhibit SCE-25, Vol. 3, pp. 17-18.

carrying costs over that GRC cycle: "[W]e believe that the monies approved in this decision combined with discretion SCE has to spend where it feels it needs to provide SCE the opportunity to address this."[1783] The decision made no mention of a permanent write-off if SCE spent money on an unauthorized project. In fact, SCE *did* ultimately spend most of the money on this project in 2013, long after the decision authorizing it, and proffered testimony in the 2015 GRC justifying its spending. SCE was thus permitted to recover the net book value of this investment.

19.1.2.1. Westminster Labs and EDEF

The Commission disallowed certain portions of the Westminster Labs capital and all of SCE's proposed EDEF expenditures in the 2015 GRC decision, which resulted in SCE forgoing any associated revenue requirement in the 2015-2017 cycle. In the pending GRC, however, in Exhibit SCE-02, Volume 11, SCE provides additional testimony and the results of an extensive survey to show that the Labs and EDEF are cost-effective and providing a benefit to ratepayers. [1784] If SCE's pending proposal is adopted, it is reasonable to recover the remaining undepreciated value of the investments. Until the Commission evaluates SCE's improved showing, TURN's blanket proposal to "remove 2018 plant balances for Westminster Labs and EDEF any amount associated with capital expenditures for 2014 and 2015" is without merit.

19.1.2.2. Pebbly Beach Automation Project

Similarly, the Commission partially accepted SCE's proposal for the Pebbly Beach Automation project in the 2015 GRC.[1785] Adopting part of the expenditures, the Commission stated that "SCE has not justified the PB project at this level of expense."[1786] SCE is not re-litigating that finding from the 2015 GRC, but in the pending proceeding, at SCE-05, Volume 5, Part 2, SCE provides extensive additional testimony describing the need for and the benefits of the automation project, and has also presented a forecast of additional capital expenditures. TURN, and any other party, had the opportunity to challenge the reasonableness of SCE's request. Whether a project should be included in rate base

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[1783] D.09-03-025, p. 196.
[1784] Exhibit SCE-02, Vol. 11, pp. 14-23 & 30-34. *See* also Exhibit SCE-18, Volume 11, Grid Technology, pp. 5-9, which also addressed testimony from TURN that is specific to the ongoing expenditures for EDEF. *See* Exhibit TURN-11, pp. 4-5.
[1785] D.15-11-021, p. 32.
[1786] D.15-11-021, p. 32.

should be based on a determination of whether the facilities are used and useful, and whether the spending is warranted at the level forecast, not on whether an earlier forecast of the proposal was once rejected by the Commission. SCE has already lost the revenue requirement associated with the Commission's decision in the 2015 GRC.[1787]

19.2. 2014-15 Capital Spending Above Authorized

TURN argues that because this GRC is the first opportunity to scrutinize 2014-2015 recorded costs, anything above what was authorized in a prior GRC at a program level invites a permanent write-off if SCE's initial showing was not as detailed as TURN would like. This is another extreme proposal that should be rejected by the Commission. SCE adequately justified the spending it incurred in support of several infrastructure replacement programs in 2014 and 2015, all in service of clear direction the Commission supports.

While SCE agrees that a determination has to be made whether SCE's pre-test year expenditures are reasonable, if the investment is spent on used and useful assets within the company's discretion given the constraints of the authorized revenue requirement for those years, it is not necessary for the Commission to graft a new requirement onto SCE's direct showing. Moreover, comparing recorded to authorized amounts cannot just be done program-by-program or year-by-year. Rather, evaluation must be made at a portfolio level in the context of GRC cycles to maintain and recognize management flexibility to address inevitable forecast variances and emergent issues. SCE's direct showing was consistent with the rate case plan and recent GRC decisions for SCE, and intervenors had every opportunity to seek additional information on past spending—and in some cases did so.[1788]

19.2.1. The Amounts Spent In Excess of Authorized Levels Were For Used and Useful Assets

As Mr. Worden testified, the bedrock principle of utility regulation is that investments must be "used and useful" to customers. Capital investments in infrastructure—or to promote safety and reliability, for example—are used and useful to customers based on consistent approval by the Commission of these types of investments that benefit customers.[1789] The reasonableness of the drivers,

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[1787] SCE did in fact write off certain parts of the project after reviewing the 2015 decision. *See* Exhibit SCE-25, Vol. 3, Appendix C.
[1788] *See, e.g.*, the discussion on pole replacements in Section 19.4., below.
[1789] Exhibit SCE-25, Vol. 3, p. 2.

cost forecasts, and scope of work for infrastructure replacement programs were discussed in significant detail in Exhibit SCE-02, Volume 8. These programs are designed to actively replace and upgrade equipment at risk of failure based on various considerations, including age, condition, performance and environmental impact. Most of these programs have been presented, discussed and litigated in great detail in prior SCE GRCs, and the Commission has generally approved the programs, at varying levels.[1790]

For example, in connection with the 2012 GRC the Commission approved underground cable spending in 2009-2011 well above the amounts that had been authorized in the 2009 decision.[1791] It is logical to conclude that the same result is reasonable for similar "inter-cycle" spending on related programs that install used and useful assets that provide customer benefits. Re-litigating the merits of these programs in a backward-looking review of spending, as TURN proposes, is redundant and unnecessary given the nature of the programs and a reasonable presumption that the spending is on used and useful assets.

The Overhead Conductor Program is a new infrastructure replacement category that was not included in SCE's request in the 2015 GRC, but was nonetheless implemented in mid-2014, incurring capital expenditures in 2015. SCE has provided significant testimony explaining the need for, and prudence of, this program in Exhibit SCE-02, Volume 8. In addition, because the primary purpose of this program is to mitigate one of the highest public safety risks SCE faces, this program is discussed in great detail in Exhibit SCE-02, Volume 1 as part of risk-informed planning and decision-making. SCE has also been transparent about its focus in this area as part of the Safety Model Assessment Proceeding (SMAP), where TURN has been an active participant. Therefore, it would be logical to conclude that the overhead conductor and branch line fuses installed as part of this program to prevent energized downed-wire related incidents, are used and useful.

Operational Facilities Maintenance[1792] entails routine work to maintain buildings and structures at substations and switching centers. The forecasts in the 2015 GRC reflected historical spending levels, but after filing the application in July 2013, emergent needs arose for additional work to expand,

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[1790] *See* D.06-05-016, pp. 232-248; D.09-03-025, pp. 203-248; D.12-11-051, pp. 146-160; D.15-11-021, pp. 61-82.

[1791] *See* Exhibit SCE-25, Vol. 3, Section II.C.1 at pp. 17-18.

[1792] Exhibit TURN-12 does not specifically mention this program, but it is an example of a large-scale program of relatively short duration that SCE had to undertake in between GRCs to address emergent security vulnerabilities.

modernize and secure control rooms for NERC-CIP physical security considerations. The scope of the program in 2014 and 2015 and the associated recorded expenditures are presented in substantial detail in Exhibit SCE-02, Volume 6 starting on page 46. Based on this testimony, it would be logical to conclude that the upgraded, modernized and secure buildings and control rooms are used and useful and providing customer value.

Mr. Worden's testimony explains SCE management's prudent discretion in reprioritizing spending to address emergent safety and security issues in 2014-2015, noting that any *delay* in addressing such risks until "prior authorization" was granted in a GRC would have been imprudent.[1793] He detailed the Commission's focus on safety and reliability-driven programs, to the point of *expecting* utilities to err in favor of investing in the electric system to preserve safe and reliable service *even if* the costs exceed the authorized amounts. For more than a decade, SCE has operated under the Reliability Investment Incentive Mechanism (RIIM), which prioritizes SCE's spending in the areas that have the most impact on safety and reliability. Most of the specific programs TURN cites (Worst Circuit Rehabilitation, Substation Transformers and Circuit Breaker Replacements, and Underground Oil switch Replacements) were part of RIIM.[1794]

The RIIM has evolved over several GRCs, but the underlying policy has remained the same. SCE must spend its authorized funding on programs included in the mechanism, or return the unspent funds to customers. The only exception occurs when some high-priority unforeseen work, such as breakdown or storm maintenance, competes for the same funding and resources. But if these high-priority activities cause SCE to incur less spending than authorized, SCE is expected to divert the leftover monies to the same safety and reliability programs within RIIM. It is important to understand that the RIIM encouraged SCE to spend above authorized levels on these programs.[1795]

When a utility is regulated in a regime of forecast test year, cost-of-service ratemaking and then incurs capital investment above authorized levels, the utility will forfeit the opportunity to recover its costs for the remainder of the GRC cycle. In other words, it will temporarily surrender its capital to utility service, lose a return on and recovery of its investment until the next GRC test year, and then true up its rate base in the next GRC to begin rate recovery of the remaining book value of the investment. SCE accepts this responsibility as its obligation to serve customers. To the extent the assets are used and

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[1793] Exhibit SCE-25, Vol. 3, p. 22.
[1794] Exhibit SCE-25, Vol. 3, pp. 22-23.
[1795] Exhibit SCE-25, Vol. 3, pp. 22-23.

useful and installed with reasonable judgment, the Company should have an opportunity to recover the remaining investment and earn its authorized rate of return.

19.2.2. The Commission Should Reject TURN's Line-Item Approach To SCE's Safety and Reliability Spending

The Commission authorizes a revenue requirement based on a forecast portfolio of projects and programs it approves in a given rate case, and expects the utility to use the available funding judiciously to manage its operations. Just as there are programs in which recorded capital expenditures are above authorized amounts, others will have recorded expenditures below authorized levels. TURN's proposal focuses only on the former, relegating the rate case to a series of unauthorized one-way balancing accounts that would result in a checkerboard of assets authorized next to those that would be written off entirely.[1796]

Among other considerations, the impact of timing of GRC decisions has to be taken into consideration in comparing authorized expenditures to recorded expenditures. Given the timing of recent GRC decisions, SCE must manage the authorized amounts over the three-year period even when there is a delay to spending in year one. Mr. Worden's testimony shows a table (reproduced below) depicting the 2012 to 2014 authorized and recorded CPUC-jurisdictional capital expenditures.[1797] Note that in 2014, SCE was managing to authorize amounts from the 2012 GRC Decision, and SCE did not spend in excess of authorized amounts over the 2012-2014 period. Moreover, 2014 adopted amounts (from the 2015 GRC) became known 22 months after 2014 started, and SCE cannot reasonably have been expected to manage to those late-adopted amounts.

[1796] Exhibit SCE-25, Vol. 3, p. 26.

[1797] Given that the Commission did not adopt capital expenditure forecasts for 2013 and 2014, SCE used the authorized post-test-year ratemaking mechanism of capital addition escalation (3.05% in 2013 and 2.93% in 2014) to estimate these "authorized" capital expenditures.

Authorized and Recorded Capital Expenditures
($ millions, CPUC Jurisdictional only)

Year	Authorized	Recorded
2012	$2,393	$1,990
2013	$2,466	$2,369
2014	$2,538	$2,927
Total	**$7,397**	**$7,286**

It is not reasonable for TURN to pluck recorded line-items in a given year, compare them to a forecast, and raise write-off alarm bells to the extent those values inevitably differ. This is especially unreasonable when the focus is placed exclusively on recorded-over-authorized (ignoring recorded-under-authorized), or when the overall portfolio of spending is not examined to offer a complete perspective.[1798]

19.2.3. TURN's New Standard For The Detail Required Before The Utility Can Recover Past Spending Is Inconsistent With Prior Decisions, Including The Rate Case Plan

TURN seeks a detailed backwards-looking justification in SCE's initial showing for 2014-2015 recorded spending-above-authorized, but that is more than what the Commission has required in the past for forecast-based GRCs. Mr. Worden's testimony shows a calendar spanning 2012-2018, detailing what the Commission's rate case plan requires the utility to show (and what the Commission uses to set rates in every GRC cycle).[1799]

For 2014 in particular, the Commission has already (a) adopted the revenue requirement based on a forecast (in the 2012 GRC); and (b) adopted a capex forecast for purposes of building up to the test year revenue requirement (in the 2015 GRC). TURN suggests that in the 2018 GRC, the recorded 2014 expenditures should be subject to rigorous review using a heightened burden of proof that the Commission has not historically asked utilities to meet in their direct showing. But SCE provided exactly what the Rate Case Plan requires for 2014—the recorded capital expenditures, by category—because they have an effect on the test year 2018 rate base. TURN's proposal, that SCE's 2014 spending-above-authorized be subject to write-off if the testimony "fails to present sufficient evidence demonstrating the reasonableness of the above-forecast spending"[1800] would create a new requirement

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[1798] Exhibit SCE-25, Vol. 3, p. 27.
[1799] Exhibit SCE-25, Vol. 3, p. 29.
[1800] Exhibit TURN-12, p. 1.

for 2014 and revisit spending authorized in two prior rate cases. That is, TURN is imposing new backward-looking standard on California's prospective GRCs, and basing its analysis on incorrect comparisons.

SCE provided sufficient detail justifying the prudency of the programs TURN cites as examples where SCE's recorded expenditures exceeded authorized levels.[1801] In reliance on the Rate Case Plan, SCE provided five years of historical data along with relevant explanations regarding recorded amounts for each capital expenditure program. SCE also complied with applicable GRC decisions to the extent the Commission directed it to provide additional analyses to demonstrate prudency of requested funding (for example the cost benefit analysis for the CRAS project). SCE's 2018 GRC testimony complies with the evidentiary standard articulated most recently in the 2015 GRC decision, which states:

> 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.[1802]

SCE provided 2015 GRC requested, authorized and recorded amounts for the base year for all O&M expense and capital expenditure categories. SCE has met its burden of proof to demonstrate the prudency of the programs and the recorded and forecast amounts in this GRC. TURN is proposing heightened standards to demonstrate prudency of capital expenditures incurred in excess of authorized for each category of spend and in years in addition to the base year. This is a higher level of detail compared to what is required by the Commission in the current Rate Case Plan and SCE's latest GRC Decision. If the Commission accepts this additional requirement going forward, SCE will, of course, comply in future GRCs, but it would be unreasonable to apply this new standard retrospectively to the 2018 GRC.

[1801] Exhibit TURN-12, p. 1.

[1802] D.15-11-021, OP 3 at p. 551. Similar direction is prescribed in the Commission's Rate Case Plan (D.89-01-040, Appendix B, pp. B22-23, Paragraph 7B).

19.3. Changes in Accounting

TURN takes issue with SCE changing its accounting policy between rate cases (for costs to mark underground locations, and for certain real property expenses). Specifically, SCE began to capitalize expenses formerly recovered via O&M, so TURN accuses the Company of "double recover[y]" of over $14 million 2013-2017.[1803] TURN's rate base adjustment proposal should be rejected because it ignores three fundamental points.

First, SCE's need to accurately and timely record its expenses to the appropriate activity—capital versus O&M—stands outside and independent of the three-year regulatory life cycle of a GRC. As Mr. Duran testified, the changes in accounting to which TURN refers are a routine part of SCE's efforts to timely update its cost recording in accordance with standard accounting practices.[1804] SCE complies with the FERC accounting guidelines, which spell out in some detail which costs can be charged to expense and capital. Good accounting practice recommends that only certain types of costs be capitalized, that there be a systematic way to allocate those costs, and that the cost assignment be applied promptly and consistently.[1805] This is true whether SCE changes its practice from O&M to capital (TURN's narrow focus), or whether it does the reverse (charging capital to O&M).

Second, TURN's alarmist charge that mid-cycle accounting changes constitute an "assault on the integrity of the future test year ratemaking process"[1806] is exaggerated and one-sided. As a technical matter, TURN is correct that in the instances on which it is choosing to focus, costs adopted as expense in a rate case decision begin being allocated to capital when inter-GRC accounting changes of this nature are implemented. This is a very small example of when recorded costs differ from authorized costs and the mismatch is short-lived. TURN has zeroed in on a five-year period, 2013-2017, in which SCE has or will record more than $14 million owing to the change in capitalization accounting. Yet over that same five-year period, SCE has spent or will spend approximately $11.9 billion in T&D capital (CPUC-jurisdictional). TURN's theory that SCE was attempting double-recovery by recording authorized expense dollars to capital and increasing recorded capital expenditures by approximately 0.1% is unfounded. TURN has not shown that SCE used its capitalization rates to materially manipulate

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[1803] Exhibit TURN-03, p. 2.
[1804] Exhibit SCE-25, Vol. 3, p. 36.
[1805] Exhibit SCE-25, Vol. 3, p. 36.
[1806] Exhibit TURN-03, p. 2.

expenses and rate base in a manner favorable to shareholders. TURN also overlooks what Mr. Worden testified to on the stand, which is that the changes in capitalization policy can and do go the other way, resulting in a similarly near-term, small benefit to ratepayers.[1807]

Third, should the Commission agree with TURN that SCE be permitted to make changes in capitalization policy only to the extent they coincide with rate case test years, this would be contrary to what SCE has been permitted to do in the past under similar circumstances, making it an unfair and abrupt change now (applied retrospectively as TURN proposes). Mr. Worden testified that in the 2012 GRC, SCE proposed a higher capitalization rate for its Facility Inventory Mapping expenses, even though it had changed capitalization policy mid-cycle (in 2010), reducing expenses by 80%. The Commission adopted SCE's revised forecast, inclusive of the accounting changes that had led to a rate base true-up.[1808]

On cross examination, Mr. Worden was asked about a different Commission precedent, involving the Florence Dam Buttress Repair project ("the dam project") in SCE's 2006 GRC, but that case is distinguishable from the changes in accounting identified in this case. In the 2003 GRC, SCE had forecast—and the Commission had approved—$800,000 of one-time O&M spending for the dam project to be completed in 2003. SCE overspent its forecast in 2003 when it competed the project, and then belatedly discovered that it had improperly recorded the expenses as O&M given its misreading of the project requirements as involving the "facing" of the dam (O&M) instead of the "resurfacing" of the dam (capital). SCE changed its accounting midcycle, and then sought recovery of the net book value of the investment in the 2006 GRC.

The Commission noted that the scope of the 2003 project had not changed, and that "SCE should not benefit, just because it make a mistake in originally classifying this project as expense."[1809] It also took issue with SCE not providing information on attrition year recorded expenses given that it had authorized three years' worth of O&M ($800,000 per year for 2003-2005) for a project finished in

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[1807] *See* SCE, Worden, Tr. 18/2326-28; *see also* Exhibit SCE-42.

[1808] The Commission did not opine on the change-in-accounting issue directly, contrary to Mr. Worden's initial recollection (compare Tr. 16/2324-25 to Tr. 16/2328), but it *did* adopt the specific reduced line-item forecast for Facility Inventory Mapping in D.12-11-051, p. 203 —and in FOF 284—consistent with SCE's testimony identifying the O&M reduction (s*ee* excerpt of testimony, included as Appendix I to Exhibit SCE-25, Vol. 3).

[1809] D.06-05-016, p. 225.

2003.[1810] The Commission appeared to be hesitant to permit recovery in the 2006 GRC of the net book value of a $1.5 million investment after SCE had already been mistakenly authorized $2.4 million of O&M expense over a three-year period. This is the "double recovery" that concerned the Commission.

By contrast, in this GRC, TURN does not dispute that SCE *should* be capitalizing ongoing expenses for underground locates and certain real estate-related expenditures going forward,[1811] and does not suggest that the old practice of recording these expenses to O&M was a "mistake"; it takes issue with the timing of SCE's accounting change. As Mr. Duran testified, TURN's proposal to "hold hostage"[1812] appropriate and timely accounting changes, potentially for years, is arbitrary and should not give rise to a rate base write-off. The accounting change SCE timely made will align ongoing costs with the appropriate accounting for the foreseeable future.

19.4. SPIDACalc Pole Issues

TURN recommends a nearly $350 million historical capital disallowance – not forward-looking capital expenditure reduction -- for money SCE invested from 2013-2016 in its Pole-Loading Program (PLP). TURN's arguments rest on several incorrect assumptions, and its disallowance request is unsupported.

First, TURN incorrectly argues that SCE imprudently selected an inappropriate software tool for its new PLP. That tool is known as SPIDACalc and referred to in this section as SPIDA. SPIDA is the software tool that is used to assess pole-loading conditions on the more than 1 million distribution and transmission poles on SCE's system. In order to implement the critical safety-related PLP on a mass level across its system, SCE necessarily had to make tradeoffs and judgment calls when procuring and implementing its new software program. But as SCE's Christine Fanous, Bill Chiu and outside expert witness Andy Stewart testified, SPIDA was the right tool for the job, all things considered.[1813] Indeed, SPIDA was far superior to some of its competitors in certain areas of importance, such as compliance with G.O. 95's data retention requirements.

Indeed, the causal chain underlying TURN's disallowance theory is severed, as it rests on the incorrect assumption that had SCE only pursued PLS-CADD benchmarking from the beginning, it

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[1810] D.06-05-016, p. 224.
[1811] Exhibit TURN-03, p. 3.
[1812] Exhibit SCE-25, Vol. 3, p. 36.
[1813] *See* Exhibit SCE-25 Vol. 3, pp. 41-42 (Fanous), pp. 45-51 (Chiu), and Attachment 1 (Stewart).

would have discovered that SPIDA was a "lemon" and would not have procured the software. But Mr. Chiu testified that any PLS-CADD testing performed at the time of procurement would *not* have revealed the "flaw" that TURN claims led to the "unnecessary" replacement of so many poles.[1814] SPIDA was competitively procured after a robust and appropriate evaluation.[1815]

Second, while it is true that SPIDA Version 5 turned out to be overly conservative for some pole configurations as compared to Version 6, SCE continued to actively work with the vendor to improve the software over time, all the while continuing to pursue its critical, public-safety-related PLP. That was a prudent policy choice, given that SPIDA represented "the best balance among accuracy, simplicity, and conservatism."[1816] Conservatism is important: While TURN is correct – and SCE has readily conceded – that SPIDA Version 5 led to the replacement of about 20% of PLP-assessed poles, while Version 6 led to the replacement of about 10% of PLP-replaced poles,[1817] that means that (a) Version 5 was consistently producing safety-oriented results compliant with G.O. 95,[1818] and (b) Version 5 was only producing "incorrect" results (albeit in an appropriate*, safety-oriented* direction) 10% of the time.[1819] But SCE was not satisfied with merely regulatory-compliant, safety-oriented results that were accurate an overwhelming majority of the time. Instead, as detailed in SCE's rebuttal testimony, SCE diligently pursued improvements to – and ultimately helped develop and procure a new version of – the SPIDA software to improve those results.[1820]

Third, TURN's disallowance recommendation vastly overestimates the alleged customer harm from using Version 5. Again, TURN makes a series of logical errors when calculating "damages." TURN – not content to limit its massive disallowance recommendation to only PLP-assessed poles – expanded its theory to non-PLP-assessed poles.[1821] But this overreach ultimately led to two serious errors, as detailed in SCE's rebuttal testimony: (1) TURN analyzed pole assessments, not pole

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[1814] *See* SCE, Chiu, Tr. 16/2285-87.
[1815] *See* Exhibit SCE-25, Vol. 3, pp. 45-47.
[1816] *See* Exhibit SCE-25, Vol. 3, p. 47.
[1817] *See* Exhibit SCE-25, Vol. 3, p. 52, fn. 104 (discussing reductions in the failure rate from 22% to 9% and 19% to 9%).
[1818] SPIDA Version 6, although less conservative than Version 5, is also producing results compliant with G.O. 95. *See* Chiu, SCE, Chiu, Tr. 16/2285.
[1819] *I.e.*, Version 5 was failing 20% of the PLP-assessed poles while it "should" have been failing 10% of the PLP-assessed poles, so it was correctly passing 80% of the poles and correctly failing 10% of the poles.
[1820] *See* Exhibit SCE-25, Vol. 3, pp. 47-51.
[1821] Non-PLP poles were also assessed with various versions of SPIDA.

replacements for non-PLP poles. It is only pole replacements that matter when calculating purported "damages."[1822] (2) TURN incorrectly assumed the failure rates for non-PLP poles would mirror PLP poles. In fact, they are vastly different.[1823]

TURN made a series of other errors in its damages calculation, including not adjusting for poles replaced for reasons other than pole-loading (*e.g.*, it is irrelevant what version of SPIDA was used when SCE replaced a pole knocked down by a car),[1824] and not correcting for poles that were already far down the "gating" process before SCE had completed the August 2015 engineering study.[1825]

But perhaps most egregious, TURN's disallowance recommendation is a permanent one: It does not adjust for the timing of when the prematurely-replaced poles would likely have been replaced anyway. That is clearly incorrect, both as a matter of logic (as all poles are eventually replaced) and fairness (it would give free poles to customers that they never have to pay for).[1826] As shown below, correcting all of these myriad errors reduces TURN's disallowance recommendation from $341 million on a PVRR basis to $21 million on a PVRR basis (before even considering the necessary reversal of customer flow-through tax benefits).[1827] The Commission should reject TURN's proposal.

Summary of Potential Financial Impact of Prematurely Replaced Non-PLP Poles (excluding necessary reversal of tax benefits)

	Scenarios	Count of Poles Replaced	Cost per pole	Pole Replacement Capital Expenditures $ Millions)	PVRR ($ Millions)
1	TURN Proposal	14,699	$14,454	$214	$218
2	Updating for actual replacement through end of 2016	4,745	$14,454	$69	$70
3	Correcting for poles actually replaced from Sep 2015-Dec 2016 and excluding Gates 5-6	1,141	$14,454	$16	$17
4	Line 3 + Correcting for eventual replacement (*i.e.*, put back into rate base after 10 years)	1,141	$14,454	$16	**$6**

[1822] *See* Exhibit SCE-25, Vol. 3, p. 53.
[1823] *See* Exhibit SCE-25, Vol. 3, p. 54.
[1824] *See* Exhibit SCE-25, Vol. 3, p. 55.
[1825] *See* Exhibit SCE-25, Vol. 3, pp. 55-56.
[1826] *See* Exhibit SCE-25, Vol. 3, pp. 56-57.
[1827] *See* Exhibit SCE-25, Vol. 3, p. 58, Tables VI-7 & VI-8.

Summary of Potential Financial Impact of Prematurely Replaced PLP Poles (excluding necessary reversal of tax benefits)

	Scenarios	Count of Poles Replaced	Cost per pole	Pole Replacement Capital Expenditures ($ Millions)	PVRR ($ Millions)
1	TURN Proposal	8,638	$14,000	$121	$123
2	Updating replacement rate reduction and extending to end of 2016	8,795	$14,000	$123	$125
3	Correcting for poles actually replaced from Sep 2015-Dec 2016 and excluding Gates 5-6	2,839	$14,000	$40	$40
4	Line 3 + Correcting for eventual replacement (*i.e.*, put back into rate base after 10 years)	2,839	$14,000	$40	**$15**

19.5. Correction for Shareholder-Assigned Costs

In late April 2017, SCE discovered a ratemaking issue leading it to conclude that a downward adjustment to SCE's rate base forecast for test year 2018 is required.[1828] During the rebuttal stage of this proceeding, which was the earliest opportunity to offer testimony describing the matter and how to correct it, Mr. Worden:

- Provided a written overview of the regulatory background governing the assignment of certain compensation costs to shareholders instead of customers;
- Explained the misalignment between SCE's accounting for capitalized overheads and their inclusion in base year plant-in-service;
- Quantified the approximate required adjustments to test year 2018 rate base; and
- Recommended next steps to address the misalignment and make customers whole for pre-2018 over-collections through a revenue requirement refund.[1829]

In brief summary, SCE applies an Administrative and General (A&G) capitalization rate and Pensions and Benefits (P&B) capitalization rate to certain qualified expenses based on how much labor is attributable to capital versus non-capital projects, which has the effect of reducing the expense and adding the capitalized portions to plant-in-service. By spreading the capitalized portions of expenses to

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[1828] In the spirit of full transparency, SCE called this issue to the attention of ORA and TURN in early June 2016, and provided in-person briefings to Energy Division employees and TURN on June 13, 2017. *See* Exhibit SCE-25, Vol. 1, p. 57.

[1829] *See* Exhibit SCE-25, Vol. 1, pp. 57-63.

plant-in-service balances, the Company eventually recovers the capitalized portion of benefit costs over asset lives, and earns a return on rate base beginning with the next GRC test year.

However, since 2006, the Commission has barred SCE from recovering through customer rates its full request for certain portions of employee compensation. Specifically, the Commission has reduced SCE's forecast of expenses to pay executive and non-executive incentive compensation, and a supplemental executive pension benefit. Over SCE's objection, the Commission has authorized rate recovery for only specified percentages or dollar amounts of SCE's forecasts, and has directed that shareholders fund the balance of the costs. In each instance where the Commission adjusted SCE's request, the text in the Commission decision assigned the costs for a specific percentage or dollar amount of these forecast expenses to shareholders. The Commission excluded from its authorized revenue requirement the forecast expenses that were allocated to shareholders.

Despite adjusting the revenue requirement to reflect the assignment of costs to shareholders, until the rebuttal stage of this rate case SCE had not made a separate adjustment to the base year plant-in-service balance to remove the portions of its capitalized costs that the Commission assigned to shareholders. Instead, since 2006, the capitalized portions of the entire recorded balances had been included inadvertently in SCE's base year plant-in-service balance in each subsequent GRC (by incorporation of the accumulated balance of the base year plant-in-service to test year rate base). The result was that SCE's rate base began to include capitalized portions of benefit outlays that the Commission specifically assigned to shareholders for cost recovery.

As shown in the table below, which is a summary of the Commission decisions on shareholder-assigned costs (reproduced from page 61 of Exhibit SCE-25, Volume 1), most of the rate base adjustments required to address this matter relate to shareholder-assigned costs of STIP, Executive Incentive Compensation (EIC) and Supplemental Employee Retirement Plan (SERP) overheads.[1830]

[1830] As Mr. Worden noted in his testimony (Exhibit SCE-25, Vol. 1, p. 60), SCE's adjustment to its rate base to reflect the Commission's prior determinations about expenses to be funded by shareholders in the summary table in no way indicates SCE's endorsement of the Commission's policy determinations in this area. To the contrary, for the reasons described in testimony by Ms. Jacqueline Trapp and Mr. Mark Bennett in Exhibit SCE-22, SCE has many defensible cost-of-service and policy reasons for recovering from rates 100 percent of costs associated with SERP, EIC, STIP and LTI, as they are legitimate and necessary components of total compensation, without which SCE would be unable to pay market compensation to its employees.

Summary of Prior Assignment of Cost Recovery To Shareholders

Expense Category	**'06 GRC**	**'09 GRC**	**'12 GRC**	**'15 GRC**
SERP	0%	50%	50%	50%
EIC	50%	50%	50%	60%
STIP	0%	0%	10%	10%
A portion of Talent Management Costs	$1.168 not authorized	$1.644 million not authorized	0%	0%
Expenses for Compliance With Affiliate Rules	$225,000 not authorized	$285,000 not authorized	$450,000 not authorized	(N/A because not requested)

To make the required rate base adjustment leading up to test year 2018, SCE identified the shareholder-assigned costs-above-authorized in rate base, by GRC period.[1831] SCE estimates that the required downward adjustment to rate base will be approximately $34 million beginning in 2018.[1832]

19.6. Rate Base – Additional Issues

This section addresses two additional issues relating to TURN's proposed rate base adjustments. First, truing up rate base in the test year of every GRC is conventional for used and useful assets and should continue. Second, findings of imprudence require fact-specific remedies, not blanket write-offs. Third, because customers have received tax timing benefits related to the investments for which TURN seeks a write-off, TURN's proposal triggers an "unwind" of those benefits under the TAMA.

[1831] *See* Exhibit SCE-25, Vol. 1, p. 63.

[1832] Apart from the GRC rate base adjustment pending in this proceeding, SCE intends to file an advice letter that makes an adjustment to the Base Revenue Requirement Balancing Account (BRRBA) to refund to customers the cumulative capital revenue requirement (depreciation, taxes, return) from 2009 through 2017, plus interest at the commercial paper rate. SCE's preliminary estimate of the refund is in the range of $10-$20 million. This refund will be allocated to all customers because the capitalized P&B/A&G was allocated across all capital accounts. SCE will also establish internal controls to prevent this problem from occurring in the future. Exhibit SCE-25, Vol. 1, pp. 63-64.

19.6.1. When the Commission Makes an Imprudence Finding, The Reason *Why* Should Inform the Remedy

The Commission may disallow prior spending for a number of reasons, not all of which lead to the same broad-brush remedy that TURN advocates. As Mr. Worden testified, when the utility spends on capital deemed not to be used and useful to customers, a full rate base adjustment may be appropriate to ensure that ratepayers pay nothing for investments that did not benefit them.[1833] As two examples, SCE appropriately elected not to re-seek recovery of $1 million of disallowed capital expenditures related to the Corporate Media Center given the Commission's determination that the center did not provide a clear benefit to customers.[1834] Another example is when SCE wrote off the full cost of its employee gym in the Test Year 2003 GRC.[1835]

By contrast, when the utility forecasts or makes investments in "used and useful" assets, but is found to have failed to meet its burden of proof to demonstrate the reasonableness of those forecast or recorded expenditures, the Commission's remedy may be to prohibit rate recovery for the three-year rate case cycle, after which the utility could—and many times does—shore up its showing and recover the net book value of its investments going forward. This step can be taken whether invited to by the Commission or not, as the utility has the burden of proof.

When, the capital investment is used and useful, but the Commission determines that the timing of the investment was premature on account of flawed decision-making by the utility with the facts available to it at the time (as was the case with aged pole replacements), the appropriate remedy would *not* be to write off the entirety of the used and useful investment. That would violate the bedrock "used and useful" standard.[1836] Rather, the Commission might examine the "overlap" between the newly installed assets, on the one hand, and the "service life" that was still remaining in the older investment it replaced. Accounting for *imprudence as to timing* is a fact-specific remedy about which reasonable minds may differ. TURN's blunt "all-or-nothing" remedy for both the aged pole replacements and the SPIDA replacements is not reasonable, particularly in instances where the utility's "premature" spending was nonetheless in service of safety objectives that utilities should not be dissuaded from striving to meet.

[1833] Exhibit SCE-25, Vol. 3, p. 2.
[1834] Exhibit SCE-25, Vol. 3, p. 2.
[1835] D.04-07-022, pp. 184-85.
[1836] *See* Exhibit SCE-25, Vol. 3, pp. 2-3.

19.6.2. Truing Up Rate Base in GRC Test Years Is Conventional and Reasonable

Even when no finding of imprudence has been made, but the utility spends more than what it was authorized in a given GRC cycle, it is customary and reasonable to "true up" rate base in the next test year.[1837] As Mr. Worden testified, the very design of forecast test year ratemaking, followed by two attrition years, leads to inevitable variances between adopted forecasts and recorded investments. These variances can result from increases in recorded costs compared to what was forecast, emergent expenses that were not anticipated at the time the rate case was filed, management discretion about the proper priorities of spend, etc.[1838] These variances—both positive and negative—are short-lived until the next rate case, with the utility sometimes earning more or less for a year or two, until the subsequent GRC when rate base is "trued-up" to reflect actual plant-in-service balances. The three-year rate case cycle thus provides a "bracket" around the effects of inter-GRC cycle spending. If a utility were to spend above authorized, all other things being equal, it will earn less than the authorized rate of return over that period because the rate recovery will not "catch up" to the spending until the rate base true-up occurs in the next test year. If the utility underspends, all other things being equal, it will earn more than the authorized rate of return over that period, but that will be short-lived because of the same rate base true-up.[1839]

Importantly, the amount of the investment "trued up" when a utility's spending exceeds authorized levels is not the *full* value of the initial investment; rather, the rate base will be trued-up by adding the *remaining* book value of those investments to rate base in the following GRC, defined as the investment less accumulated depreciation, accumulated deferred taxes, and cost of removal. In the three-year cycle when the utility spends above authorized levels, it forgoes earning the authorized rate of return from the time the capital additions were made until the next test year. To the extent the assets cost more than what the utility was authorized to collect between test years, the utility would effectively be providing free service to customers from these assets between GRC test years.[1840]

[1837] Exhibit SCE-25, Vol. 3, p. 3.
[1838] Exhibit SCE-25, Vol. 3, p. 3.
[1839] SCE, Worden, Tr. 16/2298-99 ("That's just structurally inherent in the ratemaking.").
[1840] On the flip side, if recorded capital is lower than authorized, the "trued-up" rate base in the next GRC would reflect the lower recorded amounts, with a corresponding reduction in revenue requirement passed on to customers. *See* Exhibit SCE-25, Vol. 3, pp. 3-4.

The Commission has already recognized the distinction between authorized versus recorded rate base when measured by the test year of the following GRC:

> In GRCs, capital project costs are forecasted and the authorized capital related costs are based on that amount until the next GRC, when the actual project costs would be reflected in the plant in service balances on which the annual capital-related costs such as rate of return, income taxes and deprecation would be calculated.[1841]

To the extent the utility is expected to justify expenditures above those specifically authorized, the standard is whether the utility acted reasonably. That judgment by the Commission may go to the reasonableness of the *timing* of the investment, as SCE argued in Sections 19.1.1. and 19.4, above, for aged poles and SPIDA poles, respectively.

19.6.3. TURN's Permanent Write-Off Proposals Will Have Automatic Consequences For Customers Who Received the Tax Timing Benefits Associated With the Used and Useful Investments Made

The permanent write-offs TURN seeks would have an immediate adverse impact on customers' rates because of tax consequences TURN did not mention in its testimony.[1842] Specifically, the aged poles installed by SCE in 2014 and 2015—and the pole replacements in connection with the PLP program—were eligible for a federal income tax repair deduction, which allowed SCE to deduct the *entire cost* of the new poles in the year when the costs were incurred, rather than over time. As part of SCE's normal tax accounting, SCE flowed through the federal income tax repair deduction associated with the replacement poles, and customers have received the full benefit of those deductions as a reduction in rates. On February 22, 2016, SCE filed an advice letter noting that beginning in 2012, tax deductions were significantly higher than levels assumed when the 2012 GRC authorized revenue requirement was established by the Commission (and when the 2015 GRC application was filed). Advice Letter 3368-E, stated:

> The purpose of this advice letter is to reduce Southern California Edison Company's (SCE's) Base Revenue Requirement Balancing Account (BRRBA) by $234 million to account for higher 2012-2014 repair deductions that were not reflected in rates authorized in SCE's 2012 General Rate Case (GRC) Decision D.12-11-051 or 2015 GRC D.15-11-021.

[1841] D.10-02-032, p. 130, fn. 41.
[1842] Exhibit SCE-25, Vol. 3, pp. 12, 57.

The Energy Division approved the advice letter on April 12, 2016.

Should the Commission adopt TURN's permanent write-off proposal, return of approximately $46.6 million[1843] in aged pole-related tax benefits, and tens of millions of tax timing benefit for PLP replacements,[1844] would be the next step in principled ratemaking. That is because SCE's customers should not retain the tax benefits associated with an investment that is permanently written off from SCE's rate base.

20. AFFORDABILITY

SCE's request in this case is a reasonable estimate of what it needs to help carry out Commission and State policies, provide safe, reliable and clean energy, and foster customer access and choice and meet customer desires. In developing its proposed projects and tasks, SCE has been mindful of, and cares a great deal about, the costs that our customers bear.[1845] As Mr. Payne testified to President Picker and the ALJs:

> [W]e're obviously very concerned about any time that we request a rate increase. As you know and have seen from my testimony, we've been working very hard to find every way that we can to reduce costs in the business to help our customers afford things that really are necessary in terms of replacing infrastructure on the grid, modernizing the grid so that it can play a central role in environmental improvements. So you know, we're always very concerned for our customers. We know very well who they are and we know 30 percent almost qualify for low income rates. We're very aware of that. They receive significant discounts compared to others. So I think the overall level of rates is always a concern.[1846]

SCE's capital expenditures have increased, as TURN pointed out. But SCE justified *why* those capital expenditures have increased.[1847] Many of SCE's asset populations were installed in the 1950's and 1960's; these assets are now past their mean-time-to-failure or getting very close to that point, and will only continue to age over this rate case cycle.[1848] SCE must keep its ageing system reliable and resilient for its customers -- this drives infrastructure replacement, which in turn drives reasonable but

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[1843] Exhibit SCE-25, Vol. 3, Appendix B.
[1844] Exhibit SCE-25, Vol. 3, p. 41.
[1845] *See*, e.g., Exhibit SCE-17, pp. 28-29.
[1846] SCE, Payne, Tr. 10/1298-99.
[1847] Exhibit SCE-17, p. 28, lines 10-20.
[1848] Exhibits SCE-01, pp. 10-11; SCE-17, p. 28, lines 10-20.

increased capital spending.[1849] SCE carefully balances the needs of its customers, its grid, its regulator, and its workforce.[1850]

Moreover, over the last several years SCE has implemented a number of ambitious initiatives to control our costs and more efficiently and effectively execute the work we do on behalf of our customers. Despite increasing workload and system demands, and rising costs in areas such as pensions and benefits and IT license renewals, SCE's 2018 operating expense request is close to $130 million lower than what the Commission previously authorized for 2015.[1851]

When TURN raised the issue of affordability for SCE's residential customers, SCE showed that TURN's arguments should not control the Commission's decisions on SCE's GRC request, for at least the following six reasons.

First, as TURN's testimony itself shows, the average bill for all of SCE's residential customers is substantially lower than the national average of the 50 largest investor-owned utilities.[1852]

Second, TURN made incorrect comparisons of sub-classes of customers. TURN suggested that for some SCE customers, bills are higher than the national average.[1853] But TURN took the SCE sub-group that had the largest bills (Non-CARE[1854] customers in hot climate zones) and compared this sub-group to the average bills of the entire populations at other utilities.[1855] That is not a meaningful or sound comparison. Indeed, if TURN's comparison had any validity, then it logically follows that SCE could compare the bills from SCE's CARE customers in mild climate zones to the average bills of the entire populations at other utilities.[1856] Any such comparison would show SCE's bills to be dramatically lower in comparison to other utilities. SCE of course did not make this type of distorted comparison, and TURN's attempt to do so should not be countenanced.

[1849] Exhibit SCE-17, p. 28, lines 13-15.
[1850] *Id.* at p. 28, lines 18-20.
[1851] Exhibits SCE-01, pp. 7-8, 19-21; SCE-17, pp. 28-29.
[1852] Exhibit TURN-10, p. 5; Exhibit SCE-25, Vol. 1, p. 65, lines 5-7.
[1853] Exhibit TURN-10, p. 5; Exhibit SCE-25, Vol. 1, p. 65, lines 8-10.
[1854] The CARE program provides significant rate assistance (a 33% discount) to lower income customers. *See* Exhibit SCE-25, Vol. 1, p. 69, line 3. These customers make up approximately 27% of the total residential accounts. *See* Exhibit SCE-25, Vol. 1, pp. 69-70.
[1855] Exhibit SCE-25, Vol. 1, pp. 65-67.
[1856] *Id.* at p. 67, lines 1-4.

Third, TURN noted that higher rates of poverty exist in hot climate zones. But in turn, CARE participation is significantly higher in hot climate zones.[1857] SCE showed that, because of the beneficial effects of the baseline and CARE programs, the CARE customers in hot zones pay 22% less than non-CARE customers in mild zones, even though the CARE customers consume 22% more energy.[1858]

Fourth, TURN incorrectly suggested that recent increases in customer disconnections for non-payment represent an indication of declining affordability. SCE, however, showed that the increases in customer disconnections since 2012 are more accurately described as a return to historical pre-recession norms.[1859] SCE also demonstrated that the relatively low number of disconnections in 2011 and 2012 was not due to "improved economic conditions" as suggested by TURN. The California unemployment rate was over 10% in those years.[1860] Instead, the relatively low number resulted from the Residential Disconnect OIR (R.10-02-005)[1861] and a temporary reduction in SCE resources that were available to handle credit activity.[1862]

Fifth, SCE explained that any examination of bill affordability must be placed in context. SCE demonstrated that its average residential bills, after adjusting for inflation, have remained relatively stable over the last 20 years or so.[1863]

Lastly, SCE provided uncontroverted evidence of independent customer surveys concerning the price of SCE's electric service. SCE showed that in its most recent J.D. Power national survey of residential customers, SCE ranked in the first (or best) quartile compared to nearly 60 other large utilities in how its customers viewed the price they have to pay for what they receive.[1864] Mr. Garwacki discussed this at the evidentiary hearings:

> Q Did customers say anything about affordability in the most recent J.D. Power survey?
>
> A Yes. Yes. What I alluded to, in terms of the specifics, in terms of the J.D. Power, there's an element -- a significant element that works into the overall customer satisfaction rankings associated with price. And the element that is asked is – relates to the total

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[1857] *Id.* at p. 69, lines 3-5.
[1858] *Id*. at p. 69, lines 5-7.
[1859] *Id*. at pp. 70-71.
[1860] *Id*. at p. 70, lines 10-11.
[1861] *Id*. at pp. 70-71.
[1862] SCE, Garwacki, Tr. 14/1956-1957.
[1863] Exhibit SCE-25, Vol. 1, pp. 72-73.
[1864] SCE, Garwacki, Tr. 14/1986-87; Exhibit SCE-36.

> monthly cost of your electric service. And in that particular element, SCE's ranking was in the first quartile. The first quartile being favorable in that particular case.
>
> Q Just so I understand, SCE's ranking was in the first quartile, meaning most favorable in terms of specifically what?
>
> A In terms of customers' opinions regarding the total monthly cost of your electric service, meaning affordability -- directly relating to affordability. They don't use that particular term. But it is in the first quartile in terms of customers' perceptions of the price associated with their electric service for Southern California Edison vis-à-vis, I think it's 58 large utilities around the nation. And then they also compare that relative to billing and payment services is also very significant. Power quality and reliability is a significant portion and other factors as well.[1865]

In the other major customer satisfaction element, power quality and reliability, SCE received a lower, third quartile ranking.[1866] This is a signifier of what this proceeding is all about -- striking an appropriate balance between the various customer satisfaction drivers such as affordability and reliability. SCE cares deeply about the affordability of its services to its customers, but also cares deeply about the other key customer satisfaction drivers, such as reliability. SCE has demonstrated that TURN's affordability showing was mistaken. Thus, TURN's showing should not be used as a basis for reducing the specific, prudent requests that SCE has made in this case to serve our customers.

21. RESULTS OF EXAMINATION

Following ORA's extensive examination of SCE's books and records, there are no issues in dispute. ORA made a single recommendation concerning SCE's 2015 weighted average recorded Customer Advances for Construction (CAC). As SCE stated in response to ORA data requests during the audit review, SCE had actually corrected this item in errata testimony in 2016.[1867] Moreover, this correction was reflected when SCE re-ran the Results of Operations model in conjunction with SCE's submittal of rebuttal testimony.

22. COMPLIANCE

[1865] *Id*.
[1866] *See* Exhibit SCE-36.
[1867] *See* Exhibit SCE-09, Vol. 2A, p. 45 (Table IV-14 of the errata to SCE-09, Vol. 2, as submitted on November 17, 2016).

23. CEMA BARK BEETLE RECOVERY

During a period of prolonged drought, the mountainous communities in SCE's service territory experienced an infestation of bark beetles.[1868] The beetle infestation led to millions of dead, dying, and diseased trees that created a safety hazard for the people and property in the affected areas. In Resolution E-3824, the Commission directed SCE and other utilities to mitigate the resulting fire hazard by removing the dead, dying, and diseased trees and to use their respective Catastrophic Event Memorandum Accounts (CEMA) to track the costs of those activities.[1869] Through several advice letters or applications, SCE requested and received Commission approval to recover the costs of the tree removal activities covering different time periods.[1870] In lieu of a separate application, for the $10.54 million of CEMA costs covering the period 2012-2014, SCE followed one of the procedural options listed in Resolution E-3238 and included in this 2018 GRC application a request that those costs be found reasonable. No party submitted testimony opposing that request, which should be found reasonable.

24. CALSLA ISSUES

25. OTHER ISSUES

25.1. SCE Requests Final Oral Argument

Pursuant to section 16 of the Scoping Memo and Joint Ruling of Assigned Commissioner and Administrative Law Judges issued in this proceeding, as well as Rule 13.13 of the Commission's Rules of Practice and Procedure, SCE respectfully requests a Final Oral Argument.

[1868] Exhibit SCE-12, p. 3.
[1869] *Id.* at p. 8.
[1870] *Id*. at pp. 8-11.

Respectfully submitted,

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DATE: September 8, 2017

Appendix A

Capital Expenditures

Southern California Edison
2018 GRC
Summary of Uncontested Issues for SCE Capital Expenditures Request
Nominal $ in Thousands

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
1	**SCE-02, Vol. 01**						
2	**Operational Overview and Risk-Informed Decision Making**	-	(59,872.7)	(77,459.9)	(77,302.1)	(75,950.4)	(290,585.1)
3	**T&D OpX Non-Pole Savings**						
4	T&D OpX Non-Pole Savings						
5	RO Model ID 2 : CET-OT-OT-OX-999903	-	(59,872.7)	(77,459.9)	(77,302.1)	(75,950.4)	(290,585.1)
6	**SCE-02, Vol. 02**						
7	**Customer Driven Programs**	57,599.4	71,759.7	73,567.0	75,874.9	78,287.5	357,088.5
8	**Distribution Added Facilities**						
9	Distribution Added Facilities						
10	RO Model ID 3 : CET-PD-AF-CS-MTW	3,920.8	6,899.4	7,073.2	7,295.1	7,527.0	32,715.5
11	RO Model ID 4 : CET-PD-AF-DA-MTW	11,983.6	5,907.7	6,056.4	6,246.4	6,445.1	36,639.2
12	**Relocation of Distribution Lines**						
13	Relocation of Distribution Lines						
14	RO Model ID 7 : CET-PD-CR-RL-MTW	41,695.0	58,952.7	60,437.4	62,333.4	64,315.4	287,733.8
15	**SCE-02, Vol. 03**						
16	**System Planning**	346,139.6	468,572.2	407,523.8	454,386.9	284,771.9	1,961,394.3
17	**A-Bank Plan**						
18	Saugus 220/66 kV						
19	RO Model ID 285 : CET-ET-LG-TS-610704	214.0	-	-	-	-	214.0
20	RO Model ID 286 : CET-ET-LG-TS-610705	413.2	-	-	-	-	413.2
21	RO Model ID 287 : CET-ET-LG-TS-610706	(18.8)	-	-	-	-	(18.8)
22	RO Model ID 288 : CET-ET-LG-TS-610708	56.6	-	-	-	-	56.6
23	RO Model ID 289 : CET-ET-LG-TS-610711	3,265.2	4,837.2	-	-	-	8,102.4
24	RO Model ID 290 : CET-ET-LG-TS-610712	5.9	200.0	-	-	-	205.9
25	RO Model ID 370 : CIT-00-OP-NS-000267	9.6	100.0	-	-	-	109.6
26	**Added Facilities Projects**						
27	Adjustment to Historical Contribution Rate						
28	RO Model ID 44 : CET-ET-AF-SF-395900	914.4	-	15,994.0	16,495.8	17,020.3	50,424.5
29	Clementine 115/4.16 kV						
30	RO Model ID 69 : CET-ET-CR-WC-712900	376.1	-	-	-	-	376.1
31	RO Model ID 376 : CIT-00-OP-NS-000443	116.7	-	-	-	-	116.7
32	Natural 66/12 kV						
33	RO Model ID 39 : CET-ET-AF-CF-725300	4,525.6	-	-	-	-	4,525.6
34	RO Model ID 40 : CET-RP-AF-CF-725300	46.3	-	-	-	-	46.3
35	RO Model ID 55 : CET-ET-AF-SF-725300	(18.2)	-	-	-	-	(18.2)
36	RO Model ID 56 : CET-ET-AF-SF-725301	(2.3)	-	-	-	-	(2.3)
37	RO Model ID 57 : CET-ET-AF-SF-725302	959.1	-	-	-	-	959.1
38	RO Model ID 58 : CET-ET-AF-SF-725303	5,946.2	-	-	-	-	5,946.2
39	RO Model ID 379 : CIT-00-OP-NS-000405	842.2	-	-	-	-	842.2
40	NBC Universal Expansion						
41	RO Model ID 50 : CET-ET-AF-CF-787806	-	2.2	3.6	3.6	3.6	12.9
42	RO Model ID 51 : CET-ET-AF-CF-787807	-	2.2	3.6	3.6	3.6	12.9
43	RO Model ID 36 : CET-ET-AF-CF-787805	92.5	1,392.5	2,321.5	2,321.5	2,322.4	8,450.3
44	RO Model ID 37 : CET-ET-AF-CF-787808	9.7	135.5	225.9	225.9	226.0	823.0
45	RO Model ID 38 : CET-ET-AF-CF-787809	30.4	5,700.7	9,503.6	9,503.6	9,507.3	34,245.7
46	RO Model ID 52 : CET-ET-AF-SF-787800	33.0	2,720.0	4,534.6	4,534.6	4,536.3	16,358.5
47	Niagara 66/12 kV						
48	RO Model ID 46 : CET-ET-AF-SF-784500	170.8	847.2	-	-	-	1,018.0
49	RO Model ID 47 : CET-ET-AF-SF-784501	63.6	1,816.3	-	-	-	1,879.9
50	RO Model ID 160 : CET-ET-LG-AF-784500	310.0	2,737.1	-	-	-	3,047.1
51	Projects Less than $3M						
52	RO Model ID 20 : CET-ET-AF-CF-774500	41.5	-	-	-	-	41.5
53	RO Model ID 21 : CET-ET-AF-CF-776900	837.9	-	-	-	-	837.9
54	RO Model ID 22 : CET-ET-AF-CF-777000	64.9	-	-	-	-	64.9
55	RO Model ID 23 : CET-ET-AF-CF-777001	0.2	-	-	-	-	0.2
56	RO Model ID 24 : CET-ET-AF-CF-777400	37.2	-	-	-	-	37.2
57	RO Model ID 25 : CET-ET-AF-CF-781600	677.6	-	-	-	-	677.6
58	RO Model ID 26 : CET-ET-AF-CF-781601	131.5	-	-	-	-	131.5
59	RO Model ID 27 : CET-ET-AF-CF-782800	327.7	-	-	-	-	327.7
60	RO Model ID 28 : CET-ET-AF-CF-785000	(0.1)	-	-	-	-	(0.1)
61	RO Model ID 29 : CET-ET-AF-CF-785400	39.7	-	-	-	-	39.7
62	RO Model ID 30 : CET-ET-AF-CF-785700	45.4	127.8	-	-	-	173.2
63	RO Model ID 31 : CET-ET-AF-CF-785701	1.4	6.7	-	-	-	8.1
64	RO Model ID 32 : CET-ET-AF-CF-785800	1,625.7	933.0	-	-	-	2,558.7
65	RO Model ID 33 : CET-ET-AF-CF-785801	-	152.0	-	-	-	152.0
66	RO Model ID 34 : CET-ET-AF-CF-786000	15.0	24.0	-	-	-	39.0
67	RO Model ID 35 : CET-ET-AF-CF-786200	116.8	-	-	-	-	116.8
68	RO Model ID 41 : CET-ET-AF-CF-760100	13.1	-	-	-	-	13.1
69	RO Model ID 42 : CET-ET-AF-CF-769300	22.5	-	-	-	-	22.5
70	RO Model ID 43 : CET-ET-AF-CF-769301	2,216.0	-	-	-	-	2,216.0
71	RO Model ID 45 : CET-ET-AF-SF-782900	36.9	-	-	-	-	36.9
72	RO Model ID 48 : CET-ET-AF-SF-786500	338.7	-	-	-	-	338.7
73	RO Model ID 157 : CET-ET-LG-AF-754000	7.1	-	-	-	-	7.1

Southern California Edison
2018 GRC
Summary of Uncontested Issues for SCE Capital Expenditures Request
Nominal $ in Thousands

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
74	RO Model ID 159 : CET-ET-LG-AF-766100	322.9	-	-	-	-	322.9
75	RO Model ID 399 : CIT-00-OP-NS-000484	0.1	-	-	-	-	0.1
76	**Distribution Plant Betterment**						
77	Distribution Plant Betterment						
78	RO Model ID 254 : CET-PD-LG-PB-MTW	23,288.7	13,012.4	15,828.0	16,239.5	16,669.8	85,038.4
79	**Distribution Var Plan**						
80	Distribution Var Plan						
81	RO Model ID 252 : CET-PD-LG-NC-MTW	6,386.0	5,631.1	7,322.2	7,512.5	7,711.6	34,563.4
82	**Generation Interconnection RAS**						
83	Generation Interconnection RAS						
84	RO Model ID 403 : CET-OT-OT-BP-642800	270.7	13,107.5	12,658.4	14,352.1	16,851.4	57,240.0
85	**Generator Interconnection Program**						
86	Projects Less than $3M						
87	RO Model ID 76 : CET-ET-CR-WC-742700	80.1	-	-	-	-	80.1
88	RO Model ID 77 : CET-ET-CR-WC-747000	14.8	-	-	-	-	14.8
89	RO Model ID 82 : CET-ET-CR-WC-758101	6.9	-	-	-	-	6.9
90	RO Model ID 83 : CET-ET-CR-WC-760200	1,275.4	-	-	-	-	1,275.4
91	RO Model ID 84 : CET-ET-CR-WC-760201	(1.3)	-	-	-	-	(1.3)
92	RO Model ID 85 : CET-ET-CR-WC-760202	791.7	-	-	-	-	791.7
93	RO Model ID 86 : CET-ET-CR-WC-764600	679.1	-	-	-	-	679.1
94	RO Model ID 87 : CET-ET-CR-WC-764601	458.3	-	-	-	-	458.3
95	RO Model ID 88 : CET-ET-CR-WC-764602	353.2	-	-	-	-	353.2
96	RO Model ID 89 : CET-ET-CR-WC-764603	6.2	-	-	-	-	6.2
97	RO Model ID 99 : CET-ET-CR-WC-766901	9.9	-	-	-	-	9.9
98	RO Model ID 100 : CET-ET-CR-WC-767000	0.5	-	-	-	-	0.5
99	RO Model ID 104 : CET-ET-CR-WC-769200	0.3	-	-	-	-	0.3
100	RO Model ID 105 : CET-ET-CR-WC-769201	1.5	-	-	-	-	1.5
101	RO Model ID 106 : CET-ET-CR-WC-769202	(8.6)	-	-	-	-	(8.6)
102	RO Model ID 116 : CET-ET-CR-WC-773402	0.3	-	-	-	-	0.3
103	RO Model ID 121 : CET-ET-CR-WC-775900	65.3	-	-	-	-	65.3
104	RO Model ID 122 : CET-ET-CR-WC-776000	0.4	-	-	-	-	0.4
105	RO Model ID 123 : CET-ET-CR-WC-776100	1,530.9	500.0	-	-	-	2,030.9
106	RO Model ID 124 : CET-ET-CR-WC-776101	9.9	35.4	-	-	-	45.3
107	RO Model ID 125 : CET-ET-CR-WC-776103	3,113.1	150.0	-	-	-	3,263.1
108	RO Model ID 126 : CET-ET-CR-WC-776200	29.7	-	-	-	-	29.7
109	RO Model ID 127 : CET-ET-CR-WC-776800	35.3	-	-	-	-	35.3
110	RO Model ID 134 : CET-ET-CR-WC-778000	4.1	-	-	-	-	4.1
111	RO Model ID 135 : CET-ET-CR-WC-780701	75.1	-	-	-	-	75.1
112	RO Model ID 140 : CET-ET-CR-WC-788000	40.7	59.3	-	-	-	99.9
113	RO Model ID 143 : CET-ET-CR-WC-788600	40.1	647.2	166.1	-	-	853.4
114	RO Model ID 144 : CET-ET-CR-WC-789800	27.2	-	-	-	-	27.2
115	RO Model ID 146 : CET-ET-CR-WS-786400	10.4	-	-	-	-	10.4
116	RO Model ID 147 : CET-ET-CR-WS-786401	44.2	-	-	-	-	44.2
117	RO Model ID 388 : CIT-00-OP-NS-000495	359.3	-	-	-	-	359.3
118	RO Model ID 389 : CIT-00-OP-NS-000441	289.1	-	-	-	-	289.1
119	RO Model ID 390 : CIT-00-OP-NS-000454	486.9	-	-	-	-	486.9
120	RO Model ID 397 : CIT-00-OP-NS-000497	225.5	200.0	-	-	-	425.5
121	RO Model ID 461 : CET-ET-TP-RL-755600	544.5	-	-	-	-	544.5
122	RO Model ID 536 : CET-ET-TP-RN-760200	606.0	-	-	-	-	606.0
123	**Grid Reliability Projects**						
124	Bank/Line on Breakers Projects						
125	RO Model ID 490 : CET-ET-TP-RL-781501	15.3	22.3	-	-	-	37.6
126	RO Model ID 421 : CET-ET-TP-RL-745100	1,503.2	2,850.0	-	-	-	4,353.2
127	RO Model ID 422 : CET-ET-TP-RL-745101	168.2	150.0	-	-	-	318.2
128	RO Model ID 321 : CET-ET-LG-TS-711300	4,480.8	2,000.0	-	-	-	6,480.8
129	RO Model ID 375 : CIT-00-OP-NS-000486	249.3	303.3	613.5	-	-	1,166.1
130	RO Model ID 414 : CET-ET-TP-RL-711200	1,645.9	-	-	-	-	1,645.9
131	RO Model ID 415 : CET-ET-TP-RL-711900	439.4	6,211.1	6,000.0	-	-	12,650.5
132	RO Model ID 416 : CET-ET-TP-RL-711901	0.2	-	-	-	-	0.2
133	RO Model ID 418 : CET-ET-TP-RL-724100	1,891.0	-	-	-	-	1,891.0
134	RO Model ID 426 : CET-ET-TP-RL-751800	2,709.6	2,025.0	-	-	-	4,734.6
135	RO Model ID 417 : CET-ET-TP-RL-712000	19,136.2	3,923.5	12,441.4	5,788.1	-	41,289.2
136	Digital 395 Project						
137	RO Model ID 475 : CET-ET-TP-RL-772700	5.2	-	-	-	-	5.2
138	RO Model ID 476 : CET-ET-TP-RL-772701	37.9	-	-	-	-	37.9
139	RO Model ID 478 : CET-ET-TP-RL-772703	1.0	-	-	-	-	1.0
140	RO Model ID 479 : CET-ET-TP-RL-772704	0.2	-	-	-	-	0.2
141	Mesa 500 kV Substation						
142	RO Model ID 434 : CET-ET-TP-RL-755501	-	22,607.7	20,758.3	5,450.0	-	48,815.9
143	RO Model ID 435 : CET-ET-TP-RL-755502	71.7	121.4	81.9	-	-	275.1
144	RO Model ID 436 : CET-ET-TP-RL-755503	239.0	957.3	4,463.9	948.6	-	6,608.7
145	RO Model ID 437 : CET-ET-TP-RL-755504	97.8	28.6	-	-	-	126.4
146	RO Model ID 438 : CET-ET-TP-RL-755505	4.1	5,294.0	4,655.2	0.6	-	9,953.8

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
147	RO Model ID 439 : CET-ET-TP-RL-755506	28.5	91.2	94.5	10.4	-	224.6
148	RO Model ID 440 : CET-ET-TP-RL-755507	24.8	919.4	1,248.9	2,529.5	1,296.0	6,018.6
149	RO Model ID 441 : CET-ET-TP-RL-755508	1,351.1	-	-	-	-	1,351.1
150	RO Model ID 442 : CET-ET-TP-RL-755509	0.5	81.8	18.4	-	-	100.8
151	RO Model ID 443 : CET-ET-TP-RL-755511	18.3	96.2	26.7	-	-	141.1
152	RO Model ID 445 : CET-ET-TP-RL-755513	21.2	91.8	26.4	-	-	139.4
153	RO Model ID 446 : CET-ET-TP-RL-755514	463.8	113.5	32.1	-	-	609.5
154	RO Model ID 447 : CET-ET-TP-RL-755515	6.2	217.5	73.4	-	-	297.1
155	RO Model ID 448 : CET-ET-TP-RL-755516	23.0	221.7	67.7	-	-	312.4
156	RO Model ID 449 : CET-ET-TP-RL-755517	94.3	175.6	52.3	-	-	322.2
157	RO Model ID 450 : CET-ET-TP-RL-755518	22.5	173.2	52.9	-	-	248.7
158	RO Model ID 451 : CET-ET-TP-RL-755519	15.8	174.5	51.3	-	-	241.6
159	RO Model ID 452 : CET-ET-TP-RL-755520	44.5	96.2	29.3	-	-	169.9
160	RO Model ID 453 : CET-ET-TP-RL-755521	26.5	54.3	16.0	-	-	96.8
161	RO Model ID 454 : CET-ET-TP-RL-755522	39.4	95.3	29.0	-	-	163.8
162	RO Model ID 455 : CET-ET-TP-RL-755523	47.5	43.7	11.3	-	-	102.4
163	RO Model ID 456 : CET-ET-TP-RL-755524	141.7	95.3	58.0	-	-	295.0
164	RO Model ID 457 : CET-ET-TP-RL-755525	6.6	2.9	0.7	-	-	10.1
165	RO Model ID 458 : CET-ET-TP-RL-755526	28.5	80.1	16.3	-	-	124.8
166	RO Model ID 459 : CET-ET-TP-RL-755527	7.5	21.6	5.0	-	-	34.1
167	RO Model ID 387 : CIT-00-OP-NS-000459	352.3	3,493.4	2,815.2	921.6	126.8	7,709.4
168	RO Model ID 433 : CET-ET-TP-RL-755500	10,585.9	107,090.2	60,391.1	128,333.1	142,777.2	449,177.5
169	RO Model ID 444 : CET-ET-TP-RL-755512	15.6	20,256.7	9,611.8	1,731.2	-	31,615.3
170	RO Model ID 460 : CET-RP-TP-RL-755500	5.7	1,426.0	1,426.0	1,426.0	1,426.0	5,709.7
171	Projects Less than $3M						
172	RO Model ID 487 : CET-ET-TP-RL-780600	5,821.1	-	-	-	-	5,821.1
173	RO Model ID 488 : CET-ET-TP-RL-780601	562.9	695.0	-	-	-	1,257.9
174	RO Model ID 489 : CET-ET-TP-RL-781500	798.0	4.3	-	-	-	802.3
175	RO Model ID 420 : CET-ET-TP-RL-737601	1,069.3	-	-	-	-	1,069.3
176	RO Model ID 404 : CET-ET-TP-RL-615405	189.4	-	-	-	-	189.4
177	RO Model ID 405 : CET-ET-TP-RL-615409	269.1	-	-	-	-	269.1
178	RO Model ID 413 : CET-ET-TP-RL-646800	23.5	-	-	-	-	23.5
179	RO Model ID 419 : CET-ET-TP-RL-737400	22.5	-	-	-	-	22.5
180	RO Model ID 463 : CET-ET-TP-RL-764500	4,734.5	-	-	-	-	4,734.5
181	RO Model ID 464 : CET-ET-TP-RL-764501	350.4	25.0	-	-	-	375.4
182	RO Model ID 465 : CET-ET-TP-RL-764502	147.0	-	-	-	-	147.0
183	RO Model ID 466 : CET-ET-TP-RL-764503	78.1	-	-	-	-	78.1
184	RO Model ID 468 : CET-ET-TP-RL-767800	646.5	-	-	-	-	646.5
185	RO Model ID 469 : CET-ET-TP-RL-767801	34.6	-	-	-	-	34.6
186	RO Model ID 470 : CET-ET-TP-RL-767802	32.9	-	-	-	-	32.9
187	RO Model ID 471 : CET-ET-TP-RL-767803	(197.8)	-	-	-	-	(197.8)
188	RO Model ID 472 : CET-ET-TP-RL-768000	22,151.6	12,022.3	11,632.0	-	-	45,805.8
189	RO Model ID 480 : CET-ET-TP-RL-775700	129.5	-	-	-	-	129.5
190	RO Model ID 481 : CET-ET-TP-RL-775800	14.6	-	-	-	-	14.6
191	RO Model ID 482 : CET-ET-TP-RL-775801	21.3	-	-	-	-	21.3
192	RO Model ID 484 : CET-ET-TP-RL-779000	126.1	5,543.6	3,527.7	-	-	9,197.4
193	Santiago & Ellis 66kV Circuit Breaker						
194	RO Model ID 485 : CET-ET-TP-RL-780500	1,878.7	3,177.1	-	-	-	5,055.8
195	RO Model ID 486 : CET-ET-TP-RL-780501	2,489.7	3,845.9	-	-	-	6,335.6
196	**In-Service Projects**						
197	In-Service Projects						
198	RO Model ID 502 : CET-ET-TP-RN-643801	2,495.4	-	-	-	-	2,495.4
199	RO Model ID 503 : CET-ET-TP-RN-643803	1,099.9	-	-	-	-	1,099.9
200	RO Model ID 507 : CET-ET-TP-RN-644007	(60.3)	-	-	-	-	(60.3)
201	RO Model ID 78 : CET-ET-CR-WC-755900	(38.0)	-	-	-	-	(38.0)
202	RO Model ID 156 : CET-ET-LG-AF-729900	7.7	-	-	-	-	7.7
203	RO Model ID 401 : CIT-00-OP-NS-000518	15.0	-	-	-	-	15.0
204	RO Model ID 406 : CET-ET-TP-RL-641500	(1,030.3)	-	-	-	-	(1,030.3)
205	RO Model ID 407 : CET-ET-TP-RL-641501	0.8	-	-	-	-	0.8
206	RO Model ID 408 : CET-ET-TP-RL-641502	(0.4)	-	-	-	-	(0.4)
207	RO Model ID 409 : CET-ET-TP-RL-641503	18.0	-	-	-	-	18.0
208	RO Model ID 410 : CET-ET-TP-RL-641504	38.9	-	-	-	-	38.9
209	RO Model ID 411 : CET-ET-TP-RL-641505	105.3	-	-	-	-	105.3
210	RO Model ID 501 : CET-ET-TP-RN-643800	(2,123.4)	-	-	-	-	(2,123.4)
211	RO Model ID 508 : CET-ET-TP-RN-644017	25.1	-	-	-	-	25.1
212	RO Model ID 509 : CET-ET-TP-RN-644030	2.3	932.1	-	-	-	934.4
213	RO Model ID 511 : CET-ET-TP-RN-644202	174.0	-	-	-	-	174.0
214	RO Model ID 512 : CET-ET-TP-RN-644203	3,729.2	2,768.6	2,768.6	-	-	9,266.4
215	RO Model ID 518 : CET-ET-TP-RN-706100	316.8	-	-	-	-	316.8
216	RO Model ID 519 : CET-ET-TP-RN-706101	2.9	-	-	-	-	2.9
217	RO Model ID 520 : CET-ET-TP-RN-706102	8.3	-	-	-	-	8.3
218	RO Model ID 523 : CET-ET-TP-RN-718300	(142.5)	-	-	-	-	(142.5)
219	RO Model ID 524 : CET-ET-TP-RN-718301	14.1	-	-	-	-	14.1

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
220	RO Model ID 525 : CET-ET-TP-RN-718302	706.1	2,722.1	-	-	-	3,428.2
221	RO Model ID 535 : CET-ET-TP-RN-755900	(2.6)	-	-	-	-	(2.6)
222	**Policy Driven Transmission Projects**						
223	Eldorado-Lugo-Mohave Capacitor						
224	RO Model ID 427 : CET-ET-TP-RL-754600	3,823.9	7,440.0	65,860.0	110,660.0	-	187,783.9
225	RO Model ID 429 : CET-ET-TP-RL-754603	-	700.0	16,300.0	16,900.0	-	33,900.0
226	RO Model ID 428 : CET-ET-TP-RL-754602	1,974.0	-	400.0	400.0	-	2,774.0
227	Projects Less than $3M						
228	RO Model ID 505 : CET-ET-TP-RN-643907	9,132.0	35,518.2	-	-	-	44,650.2
229	RO Model ID 506 : CET-ET-TP-RN-643908	7.9	-	-	-	-	7.9
230	RO Model ID 492 : CET-ET-TP-RN-524301	5,976.1	-	-	-	-	5,976.1
231	RO Model ID 493 : CET-ET-TP-RN-547202	22.3	-	-	-	-	22.3
232	RO Model ID 386 : CIT-00-OP-NS-000426	361.9	330.0	-	-	-	691.9
233	RO Model ID 412 : CET-ET-TP-RN-643912	643.4	-	-	-	-	643.4
234	RO Model ID 430 : CET-ET-TP-RL-754700	221.6	3,492.0	2,000.0	-	-	5,713.6
235	RO Model ID 431 : CET-ET-TP-RL-754701	217.5	5,061.0	2,785.0	-	-	8,063.5
236	RO Model ID 432 : CET-ET-TP-RL-754702	137.6	1,618.0	985.0	-	-	2,740.6
237	RO Model ID 474 : CET-ET-TP-RL-772500	(1.5)	1,700.0	16,900.0	16,700.0	-	35,298.5
238	RO Model ID 499 : CET-ET-TP-RN-643500	631.8	-	-	-	-	631.8
239	RO Model ID 500 : CET-RP-TP-RN-643500	42.5	-	-	-	-	42.5
240	RO Model ID 510 : CET-ET-TP-RN-644100	185.3	-	-	-	-	185.3
241	RO Model ID 526 : CET-ET-TP-RN-755300	6,243.5	-	-	-	-	6,243.5
242	RO Model ID 527 : CET-ET-TP-RN-755301	368.4	-	-	-	-	368.4
243	RO Model ID 528 : CET-ET-TP-RN-755302	6,416.9	-	-	-	-	6,416.9
244	RO Model ID 529 : CET-ET-TP-RN-755303	6,130.4	2,440.0	-	-	-	8,570.4
245	RO Model ID 530 : CET-ET-TP-RN-755304	67,433.9	75,119.6	-	-	-	142,553.5
246	RO Model ID 531 : CET-ET-TP-RN-755305	5,091.2	-	-	-	-	5,091.2
247	RO Model ID 532 : CET-ET-TP-RN-755306	22.4	-	-	-	-	22.4
248	RO Model ID 533 : CET-ET-TP-RN-755307	143.3	-	-	-	-	143.3
249	RO Model ID 534 : CET-RP-TP-RN-755300	308.6	1,440.0	-	-	-	1,748.6
250	RO Model ID 385 : CIT-00-OP-NS-000528	-	-	4,900.0	5,000.0	-	9,900.0
251	West of Devers Upgrade						
252	RO Model ID 494 : CET-ET-TP-RN-642003	2.3	1,009.3	200.0	-	-	1,211.6
253	RO Model ID 495 : CET-ET-TP-RN-642004	32.1	1,193.7	200.0	-	-	1,425.8
254	RO Model ID 496 : CET-ET-TP-RN-642005	56.5	4,362.5	600.0	-	-	5,019.0
255	RO Model ID 497 : CET-ET-TP-RN-642006	-	4,062.5	500.0	-	-	4,562.5
256	RO Model ID 498 : CET-RP-TP-RN-642001	1.4	2,517.0	500.0	-	-	3,018.4
257	**Right of Way**						
258	Right of Way						
259	RO Model ID 402 : CET-RP-OT-VR-107900	677.1	524.7	538.0	552.0	566.6	2,858.3
260	**Substation Expansion Projects**						
261	Projects Less than $3M						
262	RO Model ID 53 : CET-ET-AF-SF-787900	227.9	153.3	-	-	-	381.2
263	RO Model ID 54 : CET-ET-AF-SF-787901	425.7	136.3	-	-	-	562.0
264	RO Model ID 177 : CET-ET-LG-SU-541200	1,016.6	-	-	-	-	1,016.6
265	RO Model ID 198 : CET-ET-LG-SU-683600	36.9	-	2,305.6	-	-	2,342.5
266	RO Model ID 200 : CET-ET-LG-SU-697201	299.8	466.4	1,034.8	-	-	1,801.0
267	RO Model ID 206 : CET-ET-LG-SU-729301	1,134.1	-	-	-	-	1,134.1
268	RO Model ID 207 : CET-ET-LG-SU-729302	930.0	-	-	-	-	930.0
269	RO Model ID 208 : CET-ET-LG-SU-730700	966.3	-	-	-	-	966.3
270	RO Model ID 217 : CET-ET-LG-SU-757000	1.0	-	-	-	-	1.0
271	RO Model ID 222 : CET-ET-LG-SU-765100	406.3	-	-	-	-	406.3
272	RO Model ID 227 : CET-ET-LG-SU-768500	53.9	-	-	-	-	53.9
273	RO Model ID 228 : CET-ET-LG-SU-768501	957.4	-	-	-	-	957.4
274	RO Model ID 229 : CET-ET-LG-SU-768502	564.1	-	-	-	-	564.1
275	RO Model ID 230 : CET-ET-LG-SU-768503	20.8	-	-	-	-	20.8
276	RO Model ID 231 : CET-ET-LG-SU-768504	600.3	-	-	-	-	600.3
277	RO Model ID 232 : CET-ET-LG-SU-768507	661.1	20.0	-	-	-	681.1
278	RO Model ID 237 : CET-ET-LG-SU-777200	2,727.5	400.0	-	-	-	3,127.5
279	RO Model ID 238 : CET-ET-LG-SU-777300	999.4	20.0	-	-	-	1,019.4
280	RO Model ID 242 : CET-ET-LG-SU-778700	0.4	-	-	-	-	0.4
281	RO Model ID 243 : CET-ET-LG-SU-779500	10.2	20.6	6.1	-	-	36.9
282	RO Model ID 244 : CET-ET-LG-SU-779600	23.2	1,825.1	535.4	-	-	2,383.7
283	RO Model ID 246 : CET-ET-LG-SU-781000	74.7	58.5	38.2	-	-	171.3
284	RO Model ID 249 : CET-ET-LG-SU-783800	733.9	-	-	-	-	733.9
285	RO Model ID 250 : CET-ET-LG-SU-784600	-	25.7	39.5	-	-	65.2
286	RO Model ID 251 : CET-ET-LG-SU-790000	6,993.4	28.2	-	-	-	7,021.6
287	RO Model ID 191 : CET-ET-LG-SU-660300	-	-	11.9	95.4	11.9	119.2
288	Stand-alone Circuits						
289	RO Model ID 168 : CET-ET-LG-SU-459800	222.0	-	-	-	-	222.0
290	RO Model ID 179 : CET-ET-LG-SU-605100	377.2	-	-	-	-	377.2
291	RO Model ID 182 : CET-ET-LG-SU-610900	-	263.6	167.8	-	-	431.4
292	RO Model ID 186 : CET-ET-LG-SU-633600	208.1	20.0	-	-	-	228.1

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
293	RO Model ID 187 : CET-ET-LG-SU-634700	5.1	276.1	248.6	-	-	529.8
294	RO Model ID 189 : CET-ET-LG-SU-658300	34.1	35.0	300.0	-	-	369.1
295	RO Model ID 203 : CET-ET-LG-SU-703800	153.2	-	-	-	-	153.2
296	RO Model ID 205 : CET-ET-LG-SU-729000	850.7	228.0	227.1	-	-	1,305.8
297	RO Model ID 210 : CET-ET-LG-SU-748200	804.6	-	-	-	-	804.6
298	RO Model ID 211 : CET-ET-LG-SU-749200	19.1	-	-	-	-	19.1
299	RO Model ID 215 : CET-ET-LG-SU-756300	1,202.4	-	-	-	-	1,202.4
300	RO Model ID 216 : CET-ET-LG-SU-756400	159.5	-	-	-	-	159.5
301	RO Model ID 218 : CET-ET-LG-SU-757100	57.9	158.4	-	-	-	216.3
302	RO Model ID 220 : CET-ET-LG-SU-761400	292.3	-	-	-	-	292.3
303	RO Model ID 223 : CET-ET-LG-SU-766400	384.3	-	500.0	-	-	884.3
304	RO Model ID 226 : CET-ET-LG-SU-768200	230.8	15.0	-	-	-	245.8
305	RO Model ID 233 : CET-ET-LG-SU-769700	405.3	205.0	-	-	-	610.3
306	RO Model ID 235 : CET-ET-LG-SU-773200	122.9	-	-	-	-	122.9
307	RO Model ID 381 : CIT-00-OP-NS-000503	6.8	-	-	-	-	6.8
308	RO Model ID 383 : CIT-00-OP-NS-000480	4.9	-	-	-	-	4.9
309	RO Model ID 178 : CET-ET-LG-SU-543400	-	-	100.0	50.5	-	150.5
310	RO Model ID 183 : CET-ET-LG-SU-611900	-	-	-	-	2.4	2.4
311	RO Model ID 184 : CET-ET-LG-SU-629500	-	138.3	136.6	136.1	-	410.9
312	RO Model ID 185 : CET-ET-LG-SU-632800	-	16.2	113.0	145.3	-	274.5
313	RO Model ID 188 : CET-ET-LG-SU-636900	-	2.6	159.8	159.2	-	321.5
314	RO Model ID 190 : CET-ET-LG-SU-660100	1.0	-	14.6	43.3	-	58.9
315	RO Model ID 199 : CET-ET-LG-SU-686200	0.5	-	2.2	136.6	136.1	275.4
316	RO Model ID 201 : CET-ET-LG-SU-697202	31.1	782.8	4,738.6	4,969.2	-	10,521.6
317	RO Model ID 202 : CET-ET-LG-SU-697203	-	27.6	316.2	921.1	689.8	1,954.7
318	RO Model ID 214 : CET-ET-LG-SU-756200	6.0	-	360.0	587.5	-	953.5
319	RO Model ID 240 : CET-ET-LG-SU-778100	-	-	27.2	107.8	-	135.0
320	RO Model ID 241 : CET-ET-LG-SU-778400	0.4	25.4	182.5	53.5	-	261.7
321	RO Model ID 361 : CIT-00-OP-NS-000015	(1.3)	150.0	150.0	150.0	150.0	598.7
322	**Substation Monitoring Programs**						
323	Substation Monitoring Programs						
324	RO Model ID 255 : CET-ET-LG-SL-756900	273.5	-	-	-	-	273.5
325	RO Model ID 393 : CIT-00-OP-NS-000488	3.9	200.0	200.0	-	-	403.9
326	**Subtrans Lines Plan**						
327	Vestal-Mariposa 66 kV						
328	RO Model ID 341 : CET-PD-LG-TS-772600	1,180.0	-	-	-	-	1,180.0
329	Yucca Substation						
330	RO Model ID 324 : CET-ET-LG-TS-738200	3,512.9	-	-	-	-	3,512.9
331	RO Model ID 380 : CIT-00-OP-NS-000402	223.4	-	-	-	-	223.4
332	**Transmission System Generation Interconnection**						
333	Cabazon Ridge Project						
334	RO Model ID 129 : CET-ET-CR-WC-777700	-	717.5	4,741.1	4,105.8	498.7	10,063.1
335	RO Model ID 130 : CET-ET-CR-WC-777701	-	1,654.9	10,934.7	9,470.1	1,151.3	23,211.0
336	RO Model ID 131 : CET-ET-CR-WC-777702	-	0.7	4.7	4.1	0.5	10.0
337	RO Model ID 132 : CET-ET-CR-WC-777703	-	464.8	3,071.1	2,659.8	323.3	6,519.0
338	RO Model ID 133 : CET-RP-CR-WC-777700	-	186.7	1,233.8	1,068.6	129.9	2,619.0
339	Calcite 220 kV Substation						
340	RO Model ID 513 : CET-ET-TP-RN-690200	1,002.0	2,649.9	3,217.4	3,303.6	16,806.3	26,979.1
341	RO Model ID 514 : CET-ET-TP-RN-690202	-	-	-	-	125.0	125.0
342	RO Model ID 59 : CET-ET-CR-WC-690200	-	667.2	685.0	997.5	7,521.5	9,871.2
343	RO Model ID 60 : CET-ET-CR-WC-690201	-	-	-	-	3,688.6	3,688.6
344	Desert Harvest Generation						
345	RO Model ID 539 : CET-ET-TP-RN-772900	3.5	492.9	2,539.9	596.9	-	3,633.2
346	RO Model ID 110 : CET-ET-CR-WC-772900	-	7.1	36.8	8.6	-	52.6
347	RO Model ID 111 : CET-ET-CR-WC-772901	-	363.6	1,873.7	440.3	-	2,677.6
348	RO Model ID 112 : CET-ET-CR-WC-772902	-	246.6	1,270.5	298.6	-	1,815.6
349	Huntington Beach Repower						
350	RO Model ID 92 : CET-ET-CR-WC-765901	(0.1)	3,308.9	838.7	0.2	-	4,147.7
351	RO Model ID 93 : CET-ET-CR-WC-765902	47.6	127.4	-	-	-	175.0
352	RO Model ID 94 : CET-ET-CR-WC-765903	0.7	900.0	250.0	-	-	1,150.7
353	RO Model ID 95 : CET-ET-CR-WC-765904	9.3	18.8	17.8	-	-	45.9
354	RO Model ID 96 : CET-ET-CR-WC-765905	-	350.0	104.6	-	-	454.6
355	RO Model ID 97 : CET-ET-CR-WC-765906	0.7	199.3	187.9	-	-	387.9
356	Lugo-Victorville 500 kV SPS						
357	RO Model ID 398 : CIT-00-OP-NS-000475	7,802.3	2,638.0	-	-	-	10,440.3
358	RO Model ID 483 : CET-ET-TP-RL-776300	38.4	560.0	-	-	-	598.4
359	RO Model ID 542 : CET-ET-TP-RN-776300	681.0	5,342.0	70.0	-	-	6,093.0
360	RO Model ID 543 : CET-ET-TP-RN-776301	285.6	-	-	-	-	285.6
361	RO Model ID 544 : CET-ET-TP-RN-776302	27.7	5.0	58.0	-	-	90.7
362	RO Model ID 545 : CET-ET-TP-RN-776303	133.5	224.0	-	-	-	357.5
363	RO Model ID 546 : CET-ET-TP-RN-776304	612.0	9,220.0	-	-	-	9,832.0
364	RO Model ID 547 : CET-ET-TP-RN-776305	39.2	215.0	-	-	-	254.2
365	North Rosamond Generation						

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Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
366	RO Model ID 118 : CET-ET-CR-WC-775600	2.1	-	-	-	-	2.1
367	RO Model ID 119 : CET-ET-CR-WC-775601	2.1	-	-	-	-	2.1
368	RO Model ID 120 : CET-ET-CR-WC-775602	748.6	-	-	-	-	748.6
369	RO Model ID 396 : CIT-00-OP-NS-000474	18.3	280.0	-	-	-	298.3
370	RO Model ID 541 : CET-ET-TP-RN-775602	18.1	-	-	-	-	18.1
371	Projects Less than $3M						
372	RO Model ID 64 : CET-ET-CR-WC-705000	191.7	-	-	-	-	191.7
373	RO Model ID 65 : CET-ET-CR-WC-705001	(421.0)	-	-	-	-	(421.0)
374	RO Model ID 70 : CET-ET-CR-WC-724600	24.7	-	-	-	-	24.7
375	RO Model ID 71 : CET-ET-CR-WC-724601	224.9	-	-	-	-	224.9
376	RO Model ID 72 : CET-ET-CR-WC-724602	2.6	-	-	-	-	2.6
377	RO Model ID 73 : CET-ET-CR-WC-724700	7.5	-	-	-	-	7.5
378	RO Model ID 74 : CET-ET-CR-WC-724701	422.1	-	-	-	-	422.1
379	RO Model ID 79 : CET-ET-CR-WC-758000	(651.2)	-	-	-	-	(651.2)
380	RO Model ID 80 : CET-ET-CR-WC-758001	21.4	-	-	-	-	21.4
381	RO Model ID 81 : CET-ET-CR-WC-758002	1,496.3	-	-	-	-	1,496.3
382	RO Model ID 90 : CET-ET-CR-WC-765200	0.6	-	-	-	-	0.6
383	RO Model ID 91 : CET-ET-CR-WC-765300	0.6	-	-	-	-	0.6
384	RO Model ID 101 : CET-ET-CR-WC-769100	48.3	-	-	-	-	48.3
385	RO Model ID 102 : CET-ET-CR-WC-769101	396.9	-	-	-	-	396.9
386	RO Model ID 103 : CET-ET-CR-WC-769102	1,095.7	-	-	-	-	1,095.7
387	RO Model ID 108 : CET-ET-CR-WC-771900	5.4	-	-	-	-	5.4
388	RO Model ID 109 : CET-ET-CR-WC-772000	4.6	-	-	-	-	4.6
389	RO Model ID 113 : CET-ET-CR-WC-773300	21.7	-	-	-	-	21.7
390	RO Model ID 114 : CET-ET-CR-WC-773301	2,068.5	-	-	-	-	2,068.5
391	RO Model ID 115 : CET-ET-CR-WC-773302	831.6	-	-	-	-	831.6
392	RO Model ID 117 : CET-ET-CR-WC-775500	13.7	-	-	-	-	13.7
393	RO Model ID 128 : CET-ET-CR-WC-777501	(0.1)	-	-	-	-	(0.1)
394	RO Model ID 136 : CET-ET-CR-WC-786100	8.5	134.8	-	-	-	143.3
395	RO Model ID 137 : CET-ET-CR-WC-786101	3.0	-	-	-	-	3.0
396	RO Model ID 138 : CET-ET-CR-WC-786102	1.2	-	-	-	-	1.2
397	RO Model ID 139 : CET-ET-CR-WC-787300	354.5	-	-	-	-	354.5
398	RO Model ID 378 : CIT-00-OP-NS-000415	2.7	-	-	-	-	2.7
399	RO Model ID 391 : CIT-00-OP-NS-000469	146.0	-	-	-	-	146.0
400	RO Model ID 395 : CIT-00-OP-NS-000477	196.2	-	-	-	-	196.2
401	RO Model ID 467 : CET-ET-TP-RL-765700	3,017.5	-	-	-	-	3,017.5
402	RO Model ID 473 : CET-ET-TP-RL-769500	256.1	-	-	-	-	256.1
403	RO Model ID 516 : CET-ET-TP-RN-695704	-	-	5,600.0	21,800.0	31,600.0	59,000.0
404	RO Model ID 517 : CET-ET-TP-RN-705000	2,123.2	-	-	-	-	2,123.2
405	RO Model ID 521 : CET-ET-TP-RN-706200	-	5,600.0	21,800.0	31,600.0	-	59,000.0
406	RO Model ID 522 : CET-ET-TP-RN-709300	-	8.4	848.3	-	-	856.7
407	RO Model ID 537 : CET-ET-TP-RN-765000	14,234.6	500.0	-	-	-	14,734.6
408	RO Model ID 538 : CET-ET-TP-RN-769100	366.3	-	-	-	-	366.3
409	RO Model ID 540 : CET-ET-TP-RN-773300	1,952.1	-	-	-	-	1,952.1
410	RO Model ID 66 : CET-ET-CR-WC-705900	-	-	-	200.0	500.0	700.0
411	RO Model ID 67 : CET-ET-CR-WC-705901	-	-	-	100.0	200.0	300.0
412	RO Model ID 68 : CET-ET-CR-WC-705902	-	-	-	10.0	20.0	30.0
413	RO Model ID 394 : CIT-00-OP-NS-000529	-	173.8	895.3	210.4	-	1,279.5
414	RO Model ID 400 : CIT-00-OP-NS-000530	-	247.1	1,632.4	1,413.7	171.9	3,465.0
415	Sonoran & Sonoran 2						
416	RO Model ID 61 : CET-ET-CR-WC-694500	-	1,558.6	1,800.2	-	-	3,358.8
417	RO Model ID 62 : CET-ET-CR-WC-694501	-	1,209.1	1,396.5	-	-	2,605.6
418	RO Model ID 63 : CET-ET-CR-WC-694502	-	59.3	68.5	-	-	127.8
419	RO Model ID 515 : CET-ET-TP-RN-694500	-	5,595.3	6,105.3	-	-	11,700.5
420	**SCE-02, Vol. 04**						
421	**Distribution Maintenance and Inspection**	277,711.6	267,225.2	273,955.2	282,549.5	291,533.9	1,392,975.4
422	**Distribution Capital Maintenance**						
423	Distribution Capital Maintenance						
424	RO Model ID 548 : CET-PD-BM-BD-MTW	131,476.5	118,871.5	121,865.3	125,688.4	129,685.0	627,586.6
425	RO Model ID 550 : CET-PD-IR-PM-MTW	136,839.9	140,694.1	144,237.5	148,762.4	153,492.7	724,026.6
426	**Remove Idle Facilities**						
427	Remove Idle Facilities						
428	RO Model ID 549 : CET-PD-CR-IF-MTW	9,395.2	7,659.5	7,852.4	8,098.8	8,356.3	41,362.2
429	**SCE-02, Vol. 05**						
430	**Distribution Construction & Maintenance**	211,846.4	122,404.2	193,340.6	198,565.9	203,984.0	930,141.1
431	**Distribution Claims**						
432	Distribution Claims						
433	RO Model ID 551 : CET-PD-CL-DC-MTW	37,317.9	28,896.9	29,624.7	30,554.0	31,525.6	157,919.1
434	**Distribution Storm**						
435	Distribution Storm						
436	RO Model ID 557 : CET-PD-ST-DS-MTW	66,393.8	35,873.9	36,777.4	37,931.2	39,137.3	216,113.6
437	**Miscellaneous Equipment**						
438	Miscellaneous Equipment						

Southern California Edison
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Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
439	RO Model ID 553 : CET-PD-OT-DL-MTW	3,864.9	3,776.9	3,848.0	3,918.2	3,989.2	19,397.2
440	RO Model ID 554 : CET-OT-OT-FE-FUREQU	11.5	291.2	296.7	302.1	307.6	1,209.0
441	**Street Light Replacements**						
442	Street Light Replacements						
443	RO Model ID 556 : CET-PD-OT-SL-MTW	28,244.6	20,067.2	50,063.4	51,311.7	52,612.0	202,298.8
444	**Underground Structure Replacements and Shoring**						
445	Underground Structure Replacements and Shoring						
446	RO Model ID 552 : CET-PD-IR-UG-MTW	76,013.6	33,498.1	72,730.5	74,548.8	76,412.5	333,203.4
447	**SCE-02, Vol. 06**						
448	**Substation Construction & Maintenance**	105,924.7	109,129.0	95,015.9	68,014.0	66,380.2	444,463.8
449	**LADWP: NONE - PROVIDE IN SUMMARY TABLE ONLY (100% FERC)**						
450	LADWP: NONE - PROVIDE IN SUMMARY TABLE ONLY (100% FERC)						
451	RO Model ID 593 : CET-OT-OT-ME-313800	2,663.5	-	-	-	-	2,663.5
452	RO Model ID 594 : CET-OT-OT-ME-313802	7,825.4	18,662.5	5,000.0	-	-	31,487.9
453	RO Model ID 595 : CET-OT-OT-ME-313803	506.0	26,440.4	24,440.4	3,399.5	110.0	54,896.3
454	**Operational Facilities**						
455	Operational Facilities						
456	RO Model ID 592 : CET-PD-OT-FO-FACOPE	16,341.7	-	-	-	-	16,341.7
457	**Substation Capital Maintenance**						
458	Substation Capital Maintenance						
459	RO Model ID 563 : CET-ET-IR-ME-475600	3,736.3	10,982.3	11,253.1	11,549.5	11,852.2	49,373.3
460	RO Model ID 565 : CET-ET-IR-ME-619700	1,296.1	2,078.0	2,129.2	2,185.3	2,242.6	9,931.2
461	RO Model ID 558 : CET-PD-BM-SU-SUBSNW	12,702.9	8,282.6	8,486.9	8,710.4	8,938.7	47,121.4
462	RO Model ID 596 : CET-PD-OT-OC-OILCON	306.5	530.0	540.0	549.8	559.8	2,486.1
463	RO Model ID 562 : CET-ET-IR-ME-448400	1,904.0	5,004.0	5,130.0	5,291.0	5,459.2	22,788.2
464	RO Model ID 564 : CET-ET-IR-ME-475601	19,642.8	8,885.4	9,104.5	9,344.3	9,589.2	56,566.2
465	RO Model ID 570 : CET-ET-IR-ME-771500	1,357.3	1.7	1.8	1.8	1.9	1,364.6
466	RO Model ID 571 : CET-ET-IR-ME-771600	523.4	2.8	2.8	2.9	3.0	534.9
467	RO Model ID 572 : CET-ET-IR-ME-777900	5,056.5	10.2	10.5	10.8	11.1	5,099.1
468	RO Model ID 581 : CET-PD-IR-SP-SUBSNW	8,264.9	18,223.3	18,672.7	19,164.5	19,666.8	83,992.2
469	**Substation Spare Parts**						
470	Substation Spare Parts						
471	RO Model ID 559 : CET-PD-CI-CI-CRINSP	3,779.1	-	-	-	-	3,779.1
472	RO Model ID 597 : CET-PD-OT-SP-SUBSNW	13,496.2	4,549.1	4,664.2	2,122.7	2,161.2	26,993.4
473	**Substation Tools and Work Equipment**						
474	Substation Tools and Work Equipment						
475	RO Model ID 598 : CET-PD-OT-SE-SUBSNW	6,522.2	5,476.7	5,579.8	5,681.6	5,784.5	29,044.9
476	**SCE-02, Vol. 07**						
477	**Transmission Construction & Maintenance**	117,962.1	178,463.6	214,839.4	228,072.4	234,047.8	973,385.3
478	**Fiber-Optic Network Maintenance**						
479	Fiber-Optic Network Maintenance						
480	RO Model ID 603 : CCC-00-UT-OP-000110	5,208.7	6,356.0	6,475.6	6,593.7	6,713.2	31,347.1
481	**Transmission and Substation Claims**						
482	Transmission and Substation Claims						
483	RO Model ID 600 : CET-PD-CL-SC-SUBSNW	73.1	908.6	931.0	955.5	980.5	3,848.6
484	RO Model ID 601 : CET-PD-CL-TC-TREAST	4,384.8	2,815.0	2,884.4	2,960.4	3,037.9	16,082.4
485	**Transmission and Substation Storm**						
486	Transmission and Substation Storm						
487	RO Model ID 609 : CET-PD-ST-SS-SUBSNW	2,909.8	1,109.5	1,136.8	1,166.8	1,197.3	7,520.2
488	RO Model ID 610 : CET-PD-ST-TS-TREAST	5,111.7	4,796.3	4,914.6	5,044.1	5,176.3	25,042.9
489	**Transmission Breakdown Capital Maintenance**						
490	Transmission Breakdown Capital Maintenance						
491	RO Model ID 599 : CET-PD-BM-TU-TREAST	63.2	2,257.5	2,313.1	2,374.1	2,436.3	9,444.1
492	**Transmission Line Rating Remediation**						
493	Transmission Line Rating Remediation						
494	RO Model ID 606 : CET-PD-OT-PJ-TRSJAC	57,849.4	121,486.0	146,418.2	157,901.6	162,091.3	645,746.5
495	**Transmission Planned Capital Maintenance**						
496	Transmission Planned Capital Maintenance						
497	RO Model ID 604 : CET-PD-IR-TP-TREAST	27,887.6	22,943.8	33,585.2	34,469.7	35,373.2	154,259.4
498	RO Model ID 605 : CET-RP-OT-CF-FENCNG	517.2	538.8	552.1	566.7	581.5	2,756.3
499	**Transmission Relocations**						
500	Transmission Relocations						
501	RO Model ID 602 : CET-PD-CR-TR-TREAST	13,921.3	15,148.6	15,522.2	15,931.0	16,348.6	76,871.6
502	**Transmission Spare Parts**						
503	Transmission Spare Parts						
504	RO Model ID 608 : CET-PD-OT-TP-TREAST	35.3	103.6	106.2	109.0	111.8	465.9
505	**SCE-02, Vol. 08**						
506	**Infrastructure Replacement**	154,754.3	110,223.1	112,945.6	116,240.5	137,334.8	631,498.3
507	**Substation Circuit Breaker Replacement**						
508	Substation Circuit Breaker Replacement						
509	RO Model ID 615 : CET-ET-IR-CB-421100	2,425.0	5,875.8	6,020.7	6,179.3	6,859.0	27,359.8
510	RO Model ID 616 : CET-ET-IR-CB-432900	47,423.9	37,999.1	38,922.0	40,084.7	41,262.9	205,692.4
511	**Substation Transformer Bank Replacement**						

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Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
512	Substation Transformer Bank Replacement						
513	RO Model ID 623 : CET-ET-IR-TB-521000	29,798.2	15,167.0	15,541.0	15,951.0	16,369.0	92,826.2
514	RO Model ID 624 : CET-ET-IR-TB-521001	27,402.7	15,932.1	16,325.0	16,755.0	34,388.3	110,803.1
515	RO Model ID 622 : CET-ET-IR-TB-433100	47,704.6	35,249.1	36,136.9	37,270.5	38,455.6	194,816.7
516	**SCE-02, Vol. 09**						
517	**Poles**	(44,847.0)	(68,974.9)	(68,084.7)	(70,551.6)	(72,957.4)	(325,415.5)
518	**Joint Pole Capital Credit, Distribution**						
519	Joint Pole Capital Credit, Distribution						
520	RO Model ID 626 : CET-PD-CR-JD-MTW	(48,123.5)	(43,557.8)	(42,181.1)	(43,944.5)	(45,386.3)	(223,193.2)
521	RO Model ID 639 : CET-PD-CR-JD-PL	(6,380.2)	(8,056.8)	(8,584.8)	(8,854.1)	(9,135.6)	(41,011.5)
522	**Joint Pole Capital Credit, Transmission**						
523	Joint Pole Capital Credit, Transmission						
524	RO Model ID 627 : CET-PD-CR-JT-TREAST	(28.1)	(9,423.8)	(8,762.7)	(9,067.2)	(9,304.3)	(36,586.1)
525	RO Model ID 640 : CET-PD-CR-JT-PL	(435.6)	(709.1)	(1,083.7)	(1,112.2)	(1,141.3)	(4,481.8)
526	**Pole Capital Savings**						
527	Pole Capital Savings						
528	RO Model ID 635 : CET-OT-OT-OX-999902	-	(6,872.1)	(8,604.3)	(8,741.0)	(9,194.4)	(33,411.9)
529	RO Model ID 636 : CET-OT-OT-OX-999904	-	(12,965.1)	(12,528.8)	(12,921.9)	(13,332.8)	(51,748.6)
530	**Prefabrication Capital Expenditures, PLP Portion**						
531	Prefabrication Capital Expenditures, PLP Portion						
532	RO Model ID 638 : CET-PD-OT-PF-PL	2,518.3	3,637.8	4,088.3	4,216.6	4,350.7	18,811.6
533	**Transformer Capital Expenditures, PLP Portion**						
534	Transformer Capital Expenditures, PLP Portion						
535	RO Model ID 628 : CET-PD-OT-TR-PL	3,710.7	5,360.3	6,024.1	6,213.1	6,410.7	27,718.9
536	**Wood Pole Disposal**						
537	Wood Pole Disposal						
538	RO Model ID 637 : CET-PD-OT-WP-WPDISP	3,037.2	2,377.9	2,161.4	2,229.2	2,300.0	12,105.6
539	RO Model ID 641 : CET-PD-OT-WP-PL	854.3	1,234.0	1,386.9	1,430.4	1,475.8	6,381.3
540	**SCE-03, Vol. 01**						
541	**Customer Service**	3,354.7	2,785.6	2,659.7	1,794.7	2,370.7	12,965.3
542	**Specialized Equipment**						
543	Specialized Equipment						
544	RO Model ID 678 : CCS-00-SE-CO-MS-00005	-	435.0	-	-	-	435.0
545	RO Model ID 664 : CCS-00-SE-BC-PT-00001	20.7	79.3	48.1	49.6	51.2	249.0
546	RO Model ID 665 : CCS-00-SE-BC-TS-00001	1,366.1	130.2	277.4	272.9	300.9	2,347.5
547	RO Model ID 668 : CCS-00-CE-SM-OC-00001	967.4	83.2	85.3	88.0	90.8	1,314.6
548	RO Model ID 677 : CCS-00-SE-CO-MS-00001	104.6	208.0	213.3	219.9	340.4	1,086.2
549	**Structures & Improvements**						
550	Structures & Improvements						
551	RO Model ID 679 : CCS-00-SI-CO-MS-00001	-	728.1	789.0	-	-	1,517.1
552	RO Model ID 666 : CCS-00-SI-BC-AT-00001	800.0	321.0	459.1	837.8	1,043.8	3,461.8
553	RO Model ID 667 : CCS-00-SI-BC-CT-00001	95.9	800.9	787.5	326.4	543.6	2,554.3
554	**SCE-04, Vol. 01**						
555	**Hardware**	100,057.8	105,256.2	93,838.3	96,525.6	96,728.1	492,405.9
556	**Hardware**						
557	Capacity Growth for Data Center Infrastructure						
558	RO Model ID 694 : CIT-00-OP-CS-000037	1,646.8	7,500.0	7,500.0	7,500.0	7,500.0	31,646.8
559	Copper Wire Replacement						
560	RO Model ID 684 : CIT-00-OP-NS-000011	1,185.3	2,051.0	2,051.0	2,051.0	2,051.0	9,389.3
561	Data and Voice Network Replacements						
562	RO Model ID 683 : CIT-00-OP-NS-000007	17,693.8	12,006.6	11,973.9	12,110.9	12,013.3	65,798.4
563	Data Center Operations						
564	RO Model ID 698 : CIT-00-OP-CS-000064	466.9	-	-	-	-	466.9
565	RO Model ID 697 : CIT-00-OP-DC-000001	17,473.8	14,000.0	12,000.0	8,000.0	8,000.0	59,473.8
566	Disaster Recovery						
567	RO Model ID 702 : CIT-00-OP-CS-000077	-	2,900.0	2,900.0	2,700.0	2,700.0	11,200.0
568	Disk and Tape Storage						
569	RO Model ID 695 : CIT-00-OP-CS-000009	3,685.4	8,000.0	4,900.0	16,500.0	10,700.0	43,785.4
570	End User Computing						
571	RO Model ID 699 : CIT-00-OP-SM-000001	9,357.0	8,799.0	7,800.0	7,800.0	7,800.0	41,556.0
572	RO Model ID 700 : CIT-00-OP-SM-000005	8,811.7	4,701.0	3,200.0	3,200.0	3,200.0	23,112.7
573	RO Model ID 701 : CIT-00-OP-SM-000006	324.2	400.0	400.0	400.0	400.0	1,924.2
574	Fiber Replacement						
575	RO Model ID 686 : CIT-00-OP-NS-000228	1,952.4	3,964.8	3,964.8	5,003.2	5,003.2	19,888.4
576	Mainframe Servers						
577	RO Model ID 696 : CIT-00-OP-CS-000004	1,943.6	-	-	-	-	1,943.6
578	Microwave Replacement						
579	RO Model ID 685 : CIT-00-OP-NS-000224	1,763.3	4,920.0	4,920.0	4,920.0	4,920.0	21,443.3
580	Midrange Eneterprise Server Hardware						
581	RO Model ID 693 : CIT-00-OP-CS-000008	8,826.4	15,900.0	13,300.0	5,900.0	12,000.0	55,926.4
582	Mobile Radio System Replacements						
583	RO Model ID 680 : CIT-00-ET-AE-000005	2,983.0	-	-	-	-	2,983.0
584	Transmission Network & Facilities						

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585	RO Model ID 692 : CIT-00-OP-NS-000421	27.2	-	-	-	-	27.2
586	RO Model ID 691 : CIT-00-OP-NS-000096	-	117.0	117.0	117.0	117.0	468.0
587	RO Model ID 681 : CIT-00-OP-NS-000008	15,188.5	12,856.0	11,670.8	13,182.8	13,182.8	66,080.9
588	RO Model ID 682 : CIT-00-OP-NS-000331	2,067.0	500.0	500.0	500.0	500.0	4,067.0
589	RO Model ID 687 : CIT-00-OP-NS-000010	437.5	899.8	899.8	899.8	899.8	4,036.5
590	RO Model ID 688 : CIT-00-OP-NS-000024	-	26.0	26.0	26.0	26.0	104.0
591	RO Model ID 689 : CIT-00-OP-NS-000225	4,224.5	5,440.0	5,440.0	5,440.0	5,440.0	25,984.5
592	RO Model ID 690 : CIT-00-OP-NS-000026	(0.4)	275.0	275.0	275.0	275.0	1,099.6
593	**SCE-04, Vol. 02**						
594	**Capitalized Software**	21,701.7	-	-	-	-	21,701.7
595	**CS Software Projects**						
596	SCE.com Strategic Upgrade/Stabilization						
597	RO Model ID 747 : CIT-00-DM-DM-000024	4,397.7	-	-	-	-	4,397.7
598	**Ethics and Compliance**						
599	eDMRM						
600	RO Model ID 722 : CIT-00-SD-PM-000217	1,988.0	-	-	-	-	1,988.0
601	**Finance Capital Projects**						
602	Plant Ledger Update & Tax Module Installation						
603	RO Model ID 705 : CIT-00-SD-PM-000142	3,256.2	-	-	-	-	3,256.2
604	**OS Capital Projects**						
605	C-CURE 9000						
606	RO Model ID 706 : CIT-00-SD-PM-000139	938.2	-	-	-	-	938.2
607	**PS Software Projects**						
608	Commodity Management Platform						
609	RO Model ID 759 : CIT-00-SD-PM-000112	3,653.9	-	-	-	-	3,653.9
610	Generation Management System Upgrade						
611	RO Model ID 753 : CIT-00-SD-PM-000149	(125.3)	-	-	-	-	(125.3)
612	**T&D Software Projects**						
613	Centralized Remedial Action Scheme						
614	RO Model ID 795 : CIT-00-SD-PM-000102	1,634.7	-	-	-	-	1,634.7
615	Design Manager Refresh						
616	RO Model ID 787 : CIT-00-SD-PM-000152	1,184.7	-	-	-	-	1,184.7
617	Distribution Management System						
618	RO Model ID 794 : CIT-00-SD-PM-000140	2,153.6	-	-	-	-	2,153.6
619	Pole Loading Application Replacement Tool						
620	RO Model ID 798 : CIT-00-SD-PM-000137	2,619.9	-	-	-	-	2,619.9
621	**SCE-05, Vol. 01**						
622	**Palo Verde**	36,116.2	36,340.0	39,500.0	37,920.0	37,920.0	187,796.2
623	**Palo Verde**						
624	Palo Verde						
625	RO Model ID 803 : CG0-00-NU-PV-000001	8,911.3	8,239.2	3,549.3	7,193.7	9,415.9	37,309.5
626	RO Model ID 804 : CG0-00-NU-PV-000002	3,927.0	5,435.2	9,837.1	3,082.7	6,510.2	28,792.3
627	RO Model ID 805 : CG0-00-NU-PV-000003	9,318.7	2,108.5	5,852.0	6,995.3	2,243.0	26,517.5
628	RO Model ID 806 : CG0-00-NU-PV-000004	10,108.0	15,975.1	15,383.4	16,007.0	15,753.6	73,227.0
629	RO Model ID 807 : CG0-00-NU-PV-000005	3,851.1	4,582.0	4,878.3	4,641.3	3,997.4	21,950.0
630	**SCE-05, Vol. 02**						
631	**Power Procurement**	740.1	1,325.8	1,882.9	1,980.0	1,897.3	7,826.2
632	**Energy Procurement**						
633	Communication Equipment						
634	RO Model ID 808 : CSB-00-P1	724.6	1,300.8	1,857.9	1,955.0	1,872.3	7,710.6
635	RO Model ID 809 : CSB-00-PP	15.6	25.0	25.0	25.0	25.0	115.6
636	**SCE-05, Vol. 03**						
637	**Hydro**	29,031.8	61,109.0	55,763.0	42,030.1	28,684.9	216,618.8
638	**Dams & Waterways**						
639	Dams & Waterways						
640	RO Model ID 814 : CG0-00-PP-HE-000038	462.1	25.0	-	-	-	487.1
641	RO Model ID 815 : CG0-00-PP-HE-000050	0.6	5,000.0	-	-	-	5,000.6
642	RO Model ID 816 : CG0-00-PP-HE-000066	-	1,035.0	-	-	-	1,035.0
643	RO Model ID 817 : CG0-00-PP-HE-000078	-	2,668.0	-	-	-	2,668.0
644	RO Model ID 818 : CG0-00-PP-HE-000092	1,199.8	75.0	-	-	-	1,274.8
645	RO Model ID 820 : CG0-00-PP-HE-000144	567.4	-	-	-	-	567.4
646	RO Model ID 821 : CG0-00-PP-HE-000145	77.9	360.0	-	-	-	437.9
647	RO Model ID 823 : CG0-00-PP-HE-000147	-	100.0	900.0	-	-	1,000.0
648	RO Model ID 825 : CG0-00-PP-HE-000149	-	4,100.0	5,200.0	-	-	9,300.0
649	RO Model ID 826 : CG0-00-PP-HE-000150	20.4	-	-	-	-	20.4
650	RO Model ID 827 : CG0-00-PP-HE-000155	54.9	-	-	-	-	54.9
651	RO Model ID 828 : CG0-00-PP-HE-000169	-	40.0	-	-	-	40.0
652	RO Model ID 832 : CG0-00-PP-HE-000184	-	360.0	-	-	-	360.0
653	RO Model ID 835 : CG0-00-PP-HE-000196	-	-	205.0	-	-	205.0
654	RO Model ID 873 : CG0-00-PP-HE-000158	62.8	-	-	-	-	62.8
655	RO Model ID 883 : CG0-00-PP-HN-000093	2,572.4	6,000.0	-	-	-	8,572.4
656	RO Model ID 886 : CG0-00-PP-HN-000103	-	-	55.0	-	-	55.0
657	RO Model ID 912 : CG0-00-PP-HN-000069	-	1,460.3	-	-	-	1,460.3

Uncontested issues presented below include any programs, program groups, and/or projects that are not being contested in the 2018 GRC forecast period 2017-2020.

Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
658	RO Model ID 812 : CG0-00-PP-HE-000007	459.0	1,126.0	335.0	85.0	1,290.0	3,294.9
659	RO Model ID 813 : CG0-00-PP-HE-000014	628.8	1,950.0	925.0	300.0	-	3,803.8
660	RO Model ID 819 : CG0-00-PP-HE-000096	-	-	-	3,000.0	3,000.0	6,000.0
661	RO Model ID 824 : CG0-00-PP-HE-000148	171.0	111.0	115.0	119.0	124.0	640.0
662	RO Model ID 830 : CG0-00-PP-HE-000179	-	-	-	-	500.0	500.0
663	RO Model ID 831 : CG0-00-PP-HE-000182	7.5	-	-	1,800.0	-	1,807.5
664	RO Model ID 833 : CG0-00-PP-HE-000187	90.8	132.0	136.0	140.0	150.0	648.8
665	RO Model ID 881 : CG0-00-PP-HN-000027	217.1	600.0	3,399.9	3,076.1	4,070.9	11,363.9
666	RO Model ID 882 : CG0-00-PP-HN-000041	(0.0)	-	100.0	275.0	1,475.0	1,850.0
667	RO Model ID 888 : CG0-00-PP-HN-000114	-	-	50.0	426.0	-	476.0
668	RO Model ID 916 : CG0-00-PP-HN-000140	-	400.0	750.0	600.0	400.0	2,150.0
669	**Decommissioning**						
670	Decommissioning						
671	RO Model ID 880 : CG0-00-PP-HE-000017	206.8	300.0	3,000.0	3,000.0	-	6,506.8
672	**Electrical Equipment**						
673	Electrical Equipment						
674	RO Model ID 839 : CG0-00-PP-HE-000023	10.8	50.0	450.0	-	-	510.8
675	RO Model ID 840 : CG0-00-PP-HE-000055	-	2,000.0	-	-	-	2,000.0
676	RO Model ID 841 : CG0-00-PP-HE-000070	(1,313.0)	500.0	-	-	-	(813.0)
677	RO Model ID 842 : CG0-00-PP-HE-000072	2,888.0	100.0	-	-	-	2,988.0
678	RO Model ID 844 : CG0-00-PP-HE-000176	-	-	430.0	-	-	430.0
679	RO Model ID 887 : CG0-00-PP-HN-000112	29.6	-	-	-	-	29.6
680	RO Model ID 889 : CG0-00-PP-HN-000023	-	-	200.0	-	-	200.0
681	RO Model ID 891 : CG0-00-PP-HN-000037	-	840.0	2,000.0	-	-	2,840.0
682	RO Model ID 892 : CG0-00-PP-HN-000039	1,928.1	-	-	-	-	1,928.1
683	RO Model ID 893 : CG0-00-PP-HN-000106	-	-	200.0	-	-	200.0
684	RO Model ID 894 : CG0-00-PP-HN-000109	-	577.8	-	-	-	577.8
685	RO Model ID 895 : CG0-00-PP-HN-000113	99.1	1,040.0	2,100.0	-	-	3,239.1
686	RO Model ID 901 : CG0-00-PP-HN-000058	3,682.7	-	-	-	-	3,682.7
687	RO Model ID 836 : CG0-00-PP-HE-000005	175.8	-	-	-	735.0	910.8
688	RO Model ID 837 : CG0-00-PP-HE-000019	51.9	-	-	525.0	-	576.9
689	RO Model ID 838 : CG0-00-PP-HE-000022	9.8	-	-	-	2,100.0	2,109.8
690	RO Model ID 843 : CG0-00-PP-HE-000175	-	-	-	-	460.0	460.0
691	RO Model ID 846 : CG0-00-PP-HE-000186	-	150.0	150.0	150.0	-	450.0
692	**Prime Movers**						
693	Prime Movers						
694	RO Model ID 845 : CG0-00-PP-HE-000133	(7.3)	764.0	-	-	-	756.7
695	RO Model ID 854 : CG0-00-PP-HE-000042	0.2	-	764.0	-	-	764.2
696	RO Model ID 855 : CG0-00-PP-HE-000089	7.3	-	-	-	-	7.3
697	RO Model ID 857 : CG0-00-PP-HE-000100	29.2	-	-	-	-	29.2
698	RO Model ID 858 : CG0-00-PP-HE-000101	-	-	764.0	-	-	764.0
699	RO Model ID 860 : CG0-00-PP-HE-000121	531.7	-	-	-	-	531.7
700	RO Model ID 863 : CG0-00-PP-HE-000135	(4.0)	-	764.0	-	-	760.0
701	RO Model ID 864 : CG0-00-PP-HE-000136	(2.1)	742.0	-	-	-	739.9
702	RO Model ID 865 : CG0-00-PP-HE-000137	(1.2)	-	764.0	-	-	762.8
703	RO Model ID 866 : CG0-00-PP-HE-000138	(0.1)	742.0	-	-	-	741.9
704	RO Model ID 867 : CG0-00-PP-HE-000173	-	1,270.0	-	-	-	1,270.0
705	RO Model ID 868 : CG0-00-PP-HE-000190	-	-	1,350.0	-	-	1,350.0
706	RO Model ID 902 : CG0-00-PP-HN-000100	-	3,220.0	-	-	-	3,220.0
707	RO Model ID 903 : CG0-00-PP-HN-000101	-	35.0	593.8	-	-	628.8
708	RO Model ID 904 : CG0-00-PP-HN-000111	2,573.2	-	-	-	-	2,573.2
709	RO Model ID 913 : CG0-00-PP-HN-000079	-	155.0	-	-	-	155.0
710	RO Model ID 850 : CG0-00-PP-HE-000071	-	-	75.0	550.0	-	625.0
711	RO Model ID 851 : CG0-00-PP-HE-000006	75.4	235.0	660.0	575.0	975.0	2,520.4
712	RO Model ID 852 : CG0-00-PP-HE-000031	124.9	-	20.0	720.0	500.0	1,364.9
713	RO Model ID 853 : CG0-00-PP-HE-000041	1,178.7	1,320.0	1,350.0	-	988.0	4,836.7
714	RO Model ID 856 : CG0-00-PP-HE-000095	-	-	-	1,558.0	-	1,558.0
715	RO Model ID 862 : CG0-00-PP-HE-000134	(5.1)	-	-	779.0	-	773.9
716	RO Model ID 869 : CG0-00-PP-HE-000191	-	-	-	1,430.0	-	1,430.0
717	RO Model ID 870 : CG0-00-PP-HE-000192	-	-	-	1,000.0	-	1,000.0
718	RO Model ID 871 : CG0-00-PP-HE-000193	-	-	-	-	942.0	942.0
719	RO Model ID 899 : CG0-00-PP-HN-000025	-	-	-	300.0	-	300.0
720	RO Model ID 900 : CG0-00-PP-HN-000026	2,462.0	11,750.0	14,350.0	11,680.0	7,970.0	48,212.0
721	**Reclicensing**						
722	Reclicensing						
723	RO Model ID 930 : CG0-00-PP-HN-000130	-	-	20.0	-	-	20.0
724	RO Model ID 931 : CG0-00-PP-HN-000134	-	-	500.0	-	-	500.0
725	RO Model ID 884 : CG0-00-PP-HN-000096	-	1,100.0	1,950.0	-	-	3,050.0
726	RO Model ID 898 : CG0-00-PP-HN-000098	851.3	-	-	-	-	851.3
727	RO Model ID 910 : CG0-00-PP-HN-000055	542.1	200.0	-	-	-	742.1
728	RO Model ID 917 : CG0-00-PP-HN-000144	-	-	400.0	-	-	400.0
729	RO Model ID 918 : CG0-00-PP-HN-000145	-	150.0	-	-	-	150.0
730	RO Model ID 919 : CG0-00-PP-HN-000097	2,606.2	-	-	-	-	2,606.2

Southern California Edison
2018 GRC
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Nominal $ in Thousands

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Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
731	RO Model ID 920 : CG0-00-PP-HN-000116	18.3	-	-	-	-	18.3
732	RO Model ID 928 : CG0-00-PP-HN-000126	-	-	200.0	-	-	200.0
733	RO Model ID 929 : CG0-00-PP-HN-000129	-	-	10.0	72.8	-	82.8
734	RO Model ID 932 : CG0-00-PP-HN-000136	-	-	-	250.0	750.0	1,000.0
735	RO Model ID 885 : CG0-00-PP-HN-000099	50.9	-	70.0	210.0	700.0	1,030.9
736	RO Model ID 905 : CG0-00-PP-HN-000046	106.5	1,072.5	429.1	379.1	125.0	2,112.2
737	RO Model ID 906 : CG0-00-PP-HN-000050	92.4	543.8	364.1	244.1	95.0	1,339.4
738	RO Model ID 907 : CG0-00-PP-HN-000051	184.8	625.5	862.1	832.1	175.0	2,679.6
739	RO Model ID 908 : CG0-00-PP-HN-000052	92.4	569.8	499.9	234.9	120.0	1,516.9
740	RO Model ID 909 : CG0-00-PP-HN-000054	3.5	335.0	469.5	550.0	295.0	1,653.0
741	RO Model ID 911 : CG0-00-PP-HN-000056	3.5	242.5	347.5	252.0	180.0	1,025.5
742	RO Model ID 915 : CG0-00-PP-HN-000137	-	-	-	65.0	100.0	165.0
743	RO Model ID 921 : CG0-00-PP-HN-000117	-	27.0	500.0	500.0	-	1,027.0
744	RO Model ID 922 : CG0-00-PP-HN-000118	-	50.0	250.0	500.0	-	800.0
745	RO Model ID 923 : CG0-00-PP-HN-000119	-	150.0	3,500.0	500.0	-	4,150.0
746	RO Model ID 924 : CG0-00-PP-HN-000120	-	25.0	75.0	75.0	150.0	325.0
747	RO Model ID 925 : CG0-00-PP-HN-000121	-	5.0	5.0	10.0	20.0	40.0
748	RO Model ID 926 : CG0-00-PP-HN-000123	-	10.0	10.0	10.0	10.0	40.0
749	RO Model ID 927 : CG0-00-PP-HN-000124	-	5.0	-	-	20.0	25.0
750	**Structures & Grounds**						
751	Structures & Grounds						
752	RO Model ID 834 : CG0-00-PP-HE-000188	233.7	-	-	-	-	233.7
753	RO Model ID 847 : CG0-00-PP-HE-000029	-	380.0	-	-	-	380.0
754	RO Model ID 849 : CG0-00-PP-HE-000197	-	1,200.0	-	-	-	1,200.0
755	RO Model ID 872 : CG0-00-PP-HE-000086	-	-	110.0	-	-	110.0
756	RO Model ID 874 : CG0-00-PP-HE-000162	138.6	-	-	-	-	138.6
757	RO Model ID 875 : CG0-00-PP-HE-000163	98.2	-	-	-	-	98.2
758	RO Model ID 876 : CG0-00-PP-HE-000164	52.6	-	-	-	-	52.6
759	RO Model ID 877 : CG0-00-PP-HE-000165	51.3	-	-	-	-	51.3
760	RO Model ID 878 : CG0-00-PP-HE-000166	95.3	-	-	-	-	95.3
761	RO Model ID 879 : CG0-00-PP-HE-000171	-	210.0	-	-	-	210.0
762	RO Model ID 896 : CG0-00-PP-HN-000031	-	1,000.0	-	-	-	1,000.0
763	RO Model ID 914 : CG0-00-PP-HN-000082	-	1,000.0	-	-	-	1,000.0
764	RO Model ID 810 : CG0-00-PP-HE-000002	1,205.0	197.0	290.0	302.0	255.0	2,249.0
765	RO Model ID 811 : CG0-00-PP-HE-000003	(0.1)	10.0	10.0	10.0	10.0	39.9
766	RO Model ID 848 : CG0-00-PP-HE-000040	1,280.6	208.0	85.0	125.0	-	1,698.6
767	RO Model ID 859 : CG0-00-PP-HE-000106	-	-	-	450.0	-	450.0
768	RO Model ID 890 : CG0-00-PP-HN-000024	-	460.0	2,650.0	4,370.0	-	7,480.0
769	**SCE-05, Vol. 04**						
770	**Peakers and Mountainview**	59,237.1	1,425.0	3,120.0	4,090.8	13,802.1	81,675.0
771	**Moutainview**						
772	AGP/DLN 2.6+ Upgrade						
773	RO Model ID 937 : CG0-00-PP-MV-000114	46,958.9	-	-	-	-	46,958.9
774	Control Building Modifications						
775	RO Model ID 939 : CG0-00-PP-MV-000117	1,432.0	-	-	-	-	1,432.0
776	DCS Upgrade						
777	RO Model ID 940 : CG0-00-PP-MV-000119	-	-	-	-	3,819.9	3,819.9
778	GE Control Upgrade						
779	RO Model ID 941 : CG0-00-PP-MV-000120	-	-	-	1,060.8	9,547.2	10,608.0
780	MV/Peaker/Solar Control Center						
781	RO Model ID 942 : CG0-00-PP-MV-000116	4,292.3	-	-	-	-	4,292.3
782	Projects Less than $1M						
783	RO Model ID 936 : CG0-00-PP-MV-000038	265.8	650.0	-	-	-	915.8
784	Spares, Tools, Equipments						
785	RO Model ID 933 : CG0-00-PP-MV-000101	62.6	100.0	100.0	100.0	100.0	462.6
786	RO Model ID 934 : CG0-00-PP-MV-000103	132.4	215.0	220.0	230.0	235.0	1,032.4
787	**Peakers**						
788	McGrath Peaker - O&M Building						
789	RO Model ID 945 : CG0-00-PP-PK-000115	81.6	-	1,100.0	-	-	1,181.6
790	McGrath Peaker - Sewer Connection						
791	RO Model ID 949 : CG0-00-PP-PK-000130	-	-	1,600.0	-	-	1,600.0
792	Mira Loma - Street Improvements						
793	RO Model ID 947 : CG0-00-PP-PK-000128	(37.3)	-	-	-	-	(37.3)
794	Peaker - Demineralized RO						
795	RO Model ID 948 : CG0-00-PP-PK-000129	1,565.6	-	-	-	-	1,565.6
796	Peaker - Turbine Overhaul						
797	RO Model ID 946 : CG0-00-PP-MV-000121	-	-	-	2,600.0	-	2,600.0
798	Projects Less than $1M						
799	RO Model ID 944 : CG0-00-PP-PK-000103	4,483.2	360.0	-	-	-	4,843.2
800	Spares, Tools, Equipments						
801	RO Model ID 943 : CG0-00-PP-PK-000118	-	100.0	100.0	100.0	100.0	400.0
802	**SCE-05, Vol. 05**						
803	**Solar Photovoltaic & Fuel Cells**	3.8	200.0	200.0	200.0	200.0	803.8

Southern California Edison
2018 GRC
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Line	SCE Adjusted Capital Expenditures Forecast	2016	2017	2018	2019	2020	Total
804	**Solar Photovoltaic & Fuel Cells**						
805	Solar Principal Tools						
806	RO Model ID 951 : CG0-00-PP-SP-000005	-	100.0	100.0	100.0	100.0	400.0
807	Solar Spare Parts						
808	RO Model ID 950 : CG0-00-PP-SP-000004	3.8	100.0	100.0	100.0	100.0	403.8
809	**SCE-07, Vol. 02**						
810	**Corporate Environmental Services**	532.5	659.9	672.3	684.6	697.0	3,246.2
811	**Well Decommission**						
812	Well Decommission						
813	RO Model ID 962 : COS-00-EH-TS-WELL	532.5	659.9	672.3	684.6	697.0	3,246.2
814	**SCE-07, Vol. 05**						
815	**Corporate Security**	19,260.8	39,666.1	22,379.9	22,098.4	23,152.5	126,557.7
816	**NERC CIP V6 Low BES Sites**						
817	NERC CIP V6 Low BES Sites						
818	RO Model ID 993 : COS-00-CS-CS-745700	-	8,525.4	811.0	-	-	9,336.4
819	**NERC CIP-014**						
820	NERC CIP-014						
821	RO Model ID 994 : COS-00-CS-CS-782000	2,183.0	16,494.3	-	-	-	18,677.3
822	**Physical Security Systems - Electric Facilities**						
823	Physical Security Systems - Electric Facilities						
824	RO Model ID 992 : COS-00-CS-CS-745400	11.9	4,169.1	10,814.4	11,064.6	11,832.5	37,892.4
825	**Physical Security Systems - Non-Electric Facilities**						
826	Physical Security Systems - Non-Electric Facilities						
827	RO Model ID 991 : COS-00-CS-CS-SS	17,065.9	9,477.3	9,754.5	10,033.8	10,320.1	56,651.6
828	RO Model ID 995 : CIT-00-DM-DM-000067	-	1,000.0	1,000.0	1,000.0	1,000.0	4,000.0
829	**SCE-07, Vol. 06**						
830	**Supply Management & Supplier Diversity**	198.0	562.7	364.8	371.5	378.2	1,875.2
831	**Warehouse Equipment & Materials Management**						
832	Warehouse Equipment & Materials Management						
833	RO Model ID 996 : COS-00-SC-SC-FE	198.0	562.7	364.8	371.5	378.2	1,875.2
834	**SCE-07, Vol. 07**						
835	**Transportation Services**	1,460.8	6,925.3	9,257.4	6,567.6	2,558.5	26,769.6
836	**Aircraft Operations Program**						
837	Aircraft Operations Program						
838	RO Model ID 1001 : COS-00-TS-TS-AIR001	882.7	956.1	1,351.1	1,261.2	459.6	4,910.7
839	**EV Fleet Charger**						
840	EV Fleet Charger						
841	RO Model ID 997 : COS-00-TS-TS-FE0000	20.2	138.1	159.9	166.3	173.1	657.7
842	**Helicopter Lease Buyout**						
843	Helicopter Lease Buyout						
844	RO Model ID 1000 : COS-00-TS-TS-267202	-	1,614.2	4,954.6	3,184.7	-	9,753.5
845	**TSD Garage Tools & Equipment**						
846	TSD Garage Tools & Equipment						
847	RO Model ID 1002 : COS-00-TS-TS-TS0001	409.9	780.6	463.8	482.3	502.0	2,638.6
848	**Vehicle Electrification Program**						
849	Vehicle Electrification Program						
850	RO Model ID 999 : COS-00-TS-TS-VP6943	-	383.7	338.8	291.9	216.1	1,230.4
851	**Vehicle Leasehold Capital Improvements**						
852	Vehicle Leasehold Capital Improvements						
853	RO Model ID 998 : COS-00-TS-TS-VP6942	148.0	3,052.6	1,989.2	1,181.1	1,207.7	7,578.6
	Grand Total	1,498,786.6	1,455,185.0	1,455,281.2	1,490,113.5	1,355,821.5	7,255,187.7

Appendix B

O&M

Southern California Edison
2018 GRC
Summary of Uncontested Issues for SCE OOR and O&M Request
2015$ in Thousands

Uncontested issues presented below include programs and/or projects that are not being contested in the 2018 GRC forecast period.

Line	Exhibit	FERC	Activity	2018 Adjusted Forecast			
				Labor	Non-Labor	Other	Total
OTHER OPERATING REVENUES (OOR)							
1	SCE-02 Vol. 13	451	OWNERSHIP CHARGES, 451.500	–	–	1,141	**1,141**
2	SCE-02 Vol. 13	454	JOINT POLE RENTALS, 454.500	–	–	7,189	**7,189**
3	SCE-02 Vol. 13	454	COMPANY FINANCED ADDED FACILITIES, 454.300	–	–	34,909	**34,909**
4	SCE-02 Vol. 13	454	COMPANY FINANCED INTERCONNECTION FACILITIES, 454.350	–	–	15,365	**15,365**
5	SCE-02 Vol. 13	456	MISCELLANEOUS T&D REVENUES, 456.900	–	–	792	**792**
6	SCE-02 Vol. 13	456	CUSTOMER FINANCED ADDED FACILITIES AND INTERCONNECT FACILITIES, 456.700	–	–	20,550	**20,550**
7	SCE-02 Vol. 13	456	TRANSMISSION AND UTILITY SERVICES, 456.300, 456.306, 456.307 AND 456.308	–	–	48,253	**48,253**
8	SCE-02 Vol. 13	456	GENERATION RADIAL TIE LINE REVENUES, 456.319, 320	–	–	2,197	**2,197**
9	SCE-02 Vol. 13	456	HIGH DESERT TRUST FOR THE TIE LINE FACILITY RENTAL AGREEMENT, 456.323	–	–	307	**307**
10	SCE-03	450	450.100 LATE PAYMENT CHARGES - NON-RESIDENTIAL	–	–	5,779	**5,779**
11	SCE-03	450	450.150 LATE PAYMENT CHARGES - RESIDENTIAL	–	–	9,452	**9,452**
12	SCE-03	451	451.110 RETURNED CHECK CHARGES	–	–	1,396	**1,396**
13	SCE-03	451	451.300 CONNECTION CHARGE - RESIDENTIAL	–	–	7,071	**7,071**
14	SCE-03	451	451.310 CONNECTION CHARGE - NON-RESIDENTIAL	–	–	2,043	**2,043**
15	SCE-03	451	451.320 CONNECTION CHARGE - POLE	–	–	28	**28**
16	SCE-03	451	451.780 MISCELLANEOUS REVENUE - RECOVERY UNAUTHORIZED USE NON-ENERGY	–	–	103	**103**
17	SCE-03	451	451.820 SMARTCONNECT OPT-OUT	–	–	351	**351**
18	SCE-03	456	456.401 DIRECT ACCESS SERVICES	–	–	111	**111**
19	SCE-03	456	456.412 COMMUNITY CHOICE AGGREGATION SERVICE FEES	–	–	1,275	**1,275**
20	SCE-03	456	456.415 MANUFACTURED HOME BILLING SERVICE	–	–	3	**3**
21	SCE-03	456	456.924 ENERGY RELATED SERVICES	–	–	414	**414**
22	SCE-03	456	456.945 SCE ENERGYMANAGER	–	–	127	**127**
23	SCE-09 Vol. 1	453	NON TARIFFED REVENUES (453)	–	–	232	**232**
24	SCE-09 Vol. 1	453	SALES OF WATER & WATER POWER	–	–	147	**147**
25	SCE-09 Vol. 1	454	NON TARIFFED REVENUES (454)	–	–	8,816	**8,816**
26	SCE-09 Vol. 1	456	UTILITY SUBSIDIARY EARNINGS	–	–	(1,740)	**(1,740)**
27	SCE-09 Vol. 1	456	NON TARIFFED REVENUES (456)	–	–	7,624	**7,624**
28	SCE-09 Vol. 1	9992	Gains/Losses On Sale of Property	–	–	452	**452**
TOTAL OOR				-	-	**174,387**	**174,387**
OPERATIONS & MAINTENANCE (O&M)							
29	SCE-02 Vol. 03	560	560.220 - TRANSMISSION PLANNING AND GRID ENGINEERING	7,045	3,449	–	**10,494**
30	SCE-02 Vol. 03	588	588.220 - DISTRIBUTION GRID ENGINEERING AND TECHNOLOGY	2,403	1,827	–	**4,230**
31	SCE-02 Vol. 04	583	583.120 - INSPECTION OF DISTRIBUTION OVERHEAD AND UNDERGROUND LINES AND EQUIPMENT	7,583	3,732	–	**11,315**
32	SCE-02 Vol. 04	593	593.120 - PLANNED MAINTENANCE OF DISTRIBUTION OVERHEAD AND UNDERGROUND LINES AND EQUIPMENT; VEGETATION MANAGEMENT; AND APPARATUS INSPECTION AND MAINTENANCE	33,021	90,064	–	**123,085**
33	SCE-02 Vol. 04	594	594.120 - DISTRIBUTION OVERHEAD AND UNDERGROUND BREAKDOWN MAINTENANCE	13,328	12,239	–	**25,567**
34	SCE-02 Vol. 05	583	583.170 - GRID OPERATIONS - TROUBLEMEN PATROL, LOCATE, AND REPAIR ACTIVITIES	27,397	4,841	–	**32,238**
35	SCE-02 Vol. 05	586	586.140 - DESIGN CONSTRUCTION & MAINTENANCE - SET, REMOVE, AND RELOCATE METERS	6,825	3,445	–	**10,270**
36	SCE-02 Vol. 05	588	588.140 - DESIGN CONSTRUCTION & MAINTENANCE - CONSTRUCTION SUPPORT ACTIVITIES	2,854	6,240	–	**9,094**
37	SCE-02 Vol. 05	588	588.170 - GRID OPERATIONS - MISCELLANEOUS OPERATING EXPENSES	1,752	240	–	**1,992**
38	SCE-02 Vol. 06	561	561.170 - GRID OPERATIONS - MANAGEMENT AND OPERATION OF THE GRID CONTROL CENTER	7,296	2,518	–	**9,814**
39	SCE-02 Vol. 06	562	562.150 - SUBSTATION INSPECTION AND MAINTENANCE - INSPECTIONS AND MAINTENANCE ACTIVITIES PERFORMED AT SCE-OWNED GENERATING FACILITIES	1,119	455	–	**1,574**
40	SCE-02 Vol. 06	562	562.170 - GRID OPERATIONS - OPERATING TRANSMISSION STATIONS	14,387	3,537	–	**17,924**
41	SCE-02 Vol. 06	568	568.150 - SUBSTATION CONSTRUCTION & MAINTENANCE - SUPERVISION OF TRANSMISSION SUBSTATION MAINTENANCE	7,151	2,441	–	**9,592**
42	SCE-02 Vol. 06	582	582.150 - SUBSTATION INSPECTION AND MAINTENANCE - INSPECTIONS AND MAINTENANCE ACTIVITIES PERFORMED AT SCE-OWNED GENERATING FACILITIES	299	35	–	**334**
43	SCE-02 Vol. 06	582	582.170 - GRID OPERATIONS - SUPERVISING AND OPERATING DISTRIBUTION STATIONS	20,556	5,114	–	**25,670**
44	SCE-02 Vol. 06	592	592.150 - SUBSTATION CONSTRUCTION & MAINTENANCE - INSPECTION AND MAINTENANCE OF DISTRIBUTION SUBSTATION EQUIPMENT	9,726	3,514	–	**13,240**
45	SCE-02 Vol. 07	566	566.150 - TRANSMISSION - INSPECTION AND OPERATION OF TRANSMISSION LINES AND STRUCTURES	5,947	3,781	–	**9,728**
46	SCE-02 Vol. 07	573	573.170 - GRID OPERATIONS - TRANSMISSION AND SUBSTATION STORM EXPENSE	399	1,165	–	**1,564**
47	SCE-02 Vol. 11	560	560.260 - TRANSMISSION GRID TECHNOLOGY	1,609	988	–	**2,597**
48	SCE-02 Vol. 11	580	580.260 - DISTRIBUTION GRID TECHNOLOGY	8,155	5,162	–	**13,317**
49	SCE-02 Vol. 12	573	573.250 - CORPORATE ENVIRONMENTAL SERVICES WASTE MANAGEMENT - TRANSMISSION	91	155	–	**246**
50	SCE-02 Vol. 12	582	582.250 - ENVIRONMENTAL PROGRAMS - DISTRIBUTION	1,019	993	–	**2,012**
51	SCE-02 Vol. 13	567	567.150 - TRANSMISSION - LINE RENTS	–	–	17,203	**17,203**
52	SCE-02 Vol. 13	570	570.281 - TRANSMISSION PARTICIPANT SHARE COSTS	–	14,083	–	**14,083**
53	SCE-02 Vol. 13	583	583.281 - CLAIM AND COLLECTION WRITE-OFF EXPENSE	–	11,413	–	**11,413**
54	SCE-02 Vol. 13	588	588.280 - DISTRIBUTION CONSTRUCTION CONTRACT MANAGEMENT	1,170	123	–	**1,293**
55	SCE-02 Vol. 13	920921	920.220 - REAL PROPERTIES	2,412	927	–	**3,339**
56	SCE-03	901	901 - OPERATING UNIT MANAGEMENT & SUPPORT	1,731	3,391	–	**5,122**
57	SCE-03	907	907.600 - OPERATING UNIT MANAGEMENT & SUPPORT	1,824	663	–	**2,487**
58	SCE-04 Vol. 1	931	GRID SERVICES - NETWORK RENTS - 931	–	–	3,198	**3,198**
59	SCE-04 Vol. 1	920921	ENTERPRISE ARCHITECTURE & STRATEGY - 920/921	10,693	1,339	–	**12,032**
60	SCE-04 Vol. 1	920921	INFORMATION TECHNOLOGY OPERATIONAL EXCELLENCE - 920/921	–	(14,741)	–	**(14,741)**
61	SCE-04 Vol. 1	920921	SERVICE MANAGEMENT OFFICE & OPERATIONS - 920/921	14,026	72,693	–	**86,719**
62	SCE-04 Vol. 1	920921	CYBERSECURITY & COMPLIANCE 920-921	9,381	8,752	–	**18,133**
63	SCE-05 Vol. 1	524	PALO VERDE - 524	132	76,615	–	**76,747**
64	SCE-05 Vol. 2	557	POWER PROCUREMENT - 557	28,227	4,214	–	**32,441**
65	SCE-05 Vol. 3	536	536 - WATER FOR POWER	–	5,128	–	**5,128**
66	SCE-05 Vol. 3	539	539 - MISC. HYDRAULIC POWER GENERATION EXPENSES	15,970	10,809	–	**26,779**
67	SCE-05 Vol. 3	545	545 - MAINTENANCE OF MISC. HYDRAULIC PLANT	6,391	3,148	–	**9,539**
68	SCE-05 Vol. 4	506	506.013 MOHAVE	160	423	–	**583**
69	SCE-05 Vol. 4	506	506.013 MOHAVE - PART BILLING TRANS	–	(257)	–	**(257)**
70	SCE-05 Vol. 4	549	549 - GAS TURBINE PEAKER	2,107	2,629	–	**4,736**

Southern California Edison
2018 GRC
Summary of Uncontested Issues for SCE OOR and O&M Request
2015$ in Thousands

Uncontested issues presented below include programs and/or projects that are not being contested in the 2018 GRC forecast period.

Line	Exhibit	FERC	Activity	2018 Adjusted Forecast			
				Labor	Non-Labor	Other	Total
71	SCE-05 Vol. 4	549	549 - MOUNTAINVIEW	3,557	3,862	–	**7,419**
72	SCE-05 Vol. 4	554	554 - GAS TURBINE PEAKER	1,154	1,561	–	**2,715**
73	SCE-05 Vol. 4	554	554 - MOUNTAINVIEW	2,250	8,908	4,898	**16,056**
74	SCE-05 Vol. 5 Part 1	549	549 - FUEL CELL	1	361	17	**379**
75	SCE-05 Vol. 5 Part 1	549	549 - SOLAR PHOTOVOLTAIC PROGRAM	789	614	107	**1,510**
76	SCE-05 Vol. 5 Part 1	550	550 - SOLAR PHOTOVOLTAIC PROGRAM	–	2,332	–	**2,332**
77	SCE-05 Vol. 5 Part 2	549	549.140 - CATALINA GENERATION - OPERATIONS AND MAINTENANCE OF GENERATION FACILITIES	2,242	2,135	–	**4,377**
78	SCE-06 Vol. 1	923	EXECUTIVE OFFICERS - 923	–	1,547	–	**1,547**
79	SCE-06 Vol. 1	923	HUMAN RESOURCES - 923	–	6,954	–	**6,954**
80	SCE-06 Vol. 1	926	HUMAN RESOURCES - 926	4,511	598	–	**5,109**
81	SCE-06 Vol. 1	920921	HUMAN RESOURCES - 920-921	24,357	7,372	–	**31,729**
82	SCE-06 Vol. 2	926	PBOP COSTS - 926	–	417	36,406	**36,823**
83	SCE-06 Vol. 2	926	PENSION COSTS - 926	–	–	97,474	**97,474**
84	SCE-07 Vol. 1	935	SEISMIC MITIGATION - 935	–	1,533	–	**1,533**
85	SCE-07 Vol. 2	920921	ENVIRONMENTAL OPERATIONAL EXCELLENCE - 920921	(906)	(1,085)	–	**(1,991)**
86	SCE-07 Vol. 2	920921	SAN DIEGUITO WETLANDS AND WHEELER NORTH REEF - 920921	208	3,285	–	**3,493**
87	SCE-07 Vol. 2	920921	CORPORATE ENVIRONMENTAL SERVICES - 920-921	7,151	3,467	–	**10,618**
88	SCE-07 Vol. 3	566	566.282 - SUBSTATION FACILITY MAINTENANCE - CORPORATE REAL ESTATE	91	5,083	–	**5,174**
89	SCE-07 Vol. 3	580	580.282 - FIELD FACILITY MAINTENANCE - CORPORATE REAL ESTATE	305	10,009	–	**10,314**
90	SCE-07 Vol. 3	931	CORPORATE REAL ESTATE - 931	–	–	4,448	**4,448**
91	SCE-07 Vol. 3	935	CORPORATE REAL ESTATE - 935	622	13,623	–	**14,245**
92	SCE-07 Vol. 3	920921	CORPORATE REAL ESTATE - 920-921	4,992	11,814	–	**16,806**
93	SCE-07 Vol. 5	920921	CORPORATE SECURITY 920-921-923	5,553	21,353	–	**26,906**
94	SCE-07 Vol. 6	923	SUPPLIER DIVERSITY AND DEVELOPMENT - 923	–	1,966	–	**1,966**
95	SCE-07 Vol. 6	920921	SUPPLIER DIVERSITY AND DEVELOPMENT - 920-921	1,211	210	–	**1,421**
96	SCE-07 Vol. 6	920921	SUPPLY MANAGEMENT - 920-921	3,004	3,084	–	**6,088**
97	SCE-08 Vol. 1	923	COMPLIANCE, POLICY & IG - 923	–	4,985	–	**4,985**
98	SCE-08 Vol. 1	920921	NERC COMPLIANCE PROGRAM - 920921	2,806	370	–	**3,176**
99	SCE-08 Vol. 1	920921	REGULATORY COMPLIANCE - 920921	1,771	120	–	**1,891**
100	SCE-08 Vol. 1	920921	COMPLIANCE OPERATIONAL EXCELLENCE - 920921	(3,800)	(300)	–	**(4,100)**
101	SCE-08 Vol. 1	920921	COMPLIANCE, POLICY & IG - 920921	3,398	513	–	**3,911**
102	SCE-08 Vol. 2	930	CORPORATE COMMUNICATIONS - 930 - COMMUNICATIONS PRODUCTS	–	5,828	–	**5,828**
103	SCE-08 Vol. 2	920921	LOCAL PUBLIC AFFAIRS - 920-921	6,562	1,342	–	**7,904**
104	SCE-08 Vol. 3	926	FINANCIAL SERVICES - 926	269	62	–	**331**
105	SCE-08 Vol. 3	926	PARTICIPANT CREDITS - 926	–	–	9,867	**9,867**
106	SCE-08 Vol. 3	930	PARTICIPANT CREDITS - 930	–	11,255	–	**11,255**
107	SCE-08 Vol. 4	925	WORKERS' COMPENSATION - 925	3,513	3,270	–	**6,783**
108	SCE-08 Vol. 4	925	WORKERS' COMPENSATION RESERVE - 925	–	7,811	–	**7,811**
109	SCE-08 Vol. 4	926	DISABILITY ADMINISTRATION - 926	805	28	–	**833**
110	SCE-08 Vol. 5	924	CORP PROPERTY INSURANCE - 924	–	–	14,070	**14,070**
111	SCE-09 Vol. 1	920921	SONGS DECOMMISSIONING CREDITS - 920921	(2,817)	(3,294)	–	**(6,111)**
112	SCE-11	905	Accessibility Issues	250	1,250	–	**1,500**
TOTAL UNCONTESTED O&M				**348,035**	**501,530**	**187,688**	**1,037,253**
TOTAL UNCONTESTED OOR & O&M				**348,035**	**501,530**	**362,075**	**1,211,640**

Appendix C

Ratemaking

Southern California Edison
2018 GRC
Uncontested Balancing and Memorandum Account Proposals

Line	Account	SCE Proposal	ORA Position	TURN Position
1	Medical Programs Balancing Account (MPBA)	Retain 2-way account	Uncontested	Uncontested
2	Pension Costs Balancing Account (PCBA)	Retain 2-way account	ORA supports continuation of the account (ORA-21)	Uncontested
3	Post-Employment Benefits Other than Pensions Costs Balancing Account (PBOP BA)	Retain 2-way account	Uncontested	Uncontested
4	Results Sharing Memorandum Account (RSMA)	Retain 1-way account / rename "STIPMA" and Capitalize using SCE's proposed P&B capitalization rate	Uncontested	Uncontested
5	Tax Accounting Memorandum Account (TAMA)	Retain 2-way account through 2018 GRC period	ORA does not oppose continuation of the account (ORA-02)	Uncontested
6	Residential Rate Implementation Memorandum Account (RRIMA) for TOU Pilot 1/	Recover 12/31/17 balance; 2018 - 2020 annual recovery in ERRA Review proceeding	ORA does not object to SCE's proposal (ORA-22)	Uncontested
7	Energy Data Request Program Memorandum Account (EDRPMA) 1/	Eliminate account and recover 12/31/17 balance	ORA does not object to SCE's proposal (ORA-22)	Uncontested
8	Marine Corps Air Ground Combat Center Memorandum Account (MCAGCCMA)	Eliminate account and allocate $1M after-tax gain to shareholders	ORA does not object to SCE's proposal (ORA-22)	Uncontested
9	Project Development Division Memorandum Account (PDDMA)	Eliminate account	ORA does not object to SCE's proposal (ORA-22)	Uncontested
10	Residential Service Disconnection Memorandum Account (RSDMA) 1/	Eliminate account and recover 12/31/17 balance	ORA does not object to SCE's proposal (ORA-22)	Uncontested
11	SmartConnect Opt-Out Balancing Account (SOBA) 1/	Eliminate account and recover 12/31/17 balance	ORA does not object to SCE's proposal (ORA-22)	Uncontested
12	Bark Beetle CEMA	Recover $10M in 2012 - 2014 costs	ORA does not object to SCE's proposal (ORA-22)	Uncontested
13	DER Deferred Project Memorandum Account (DERDPMA)	SCE withdrew its request to establish this account to track 2018 GRC authorized rev. req. upon a project's deferral (net of amounts spent) for refund once a DER solution is determined to meet the current need for the project	n/a	n/a
14	Customer Data Access (CDA) Costs	Cease entries to BRRBA	ORA does not object to SCE's proposal (ORA-22)	Uncontested

1/ **SCE will provide the most recent recorded balance in Update Testimony, with a final year-end 2017 balance provided in the advice letter implementing the 2018 GRC decision.**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2018, Among Other Things, And To Reflect That Increase In Rates.	Application No. 16-09-001 (Filed September 1, 2016)

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **OPENING BRIEF OF SOUTHERN CALIFORNIA EDISON COMPANY (U-338 E)** on all parties identified on the attached service list(s) **A.16-09-001.** Service was effected by one or more means indicated below:

☒ Transmitting the copies via e-mail to all parties who have provided an e-mail address.

☒ Placing copies in sealed envelopes and causing such envelopes to be delivered by U.S. Mail to the offices of the ALJ(s) or other addressee(s).

ALJ Eric Wildgrube
CPUC
505 Van Ness Ave
San Francisco, CA 94102

ALJ Stephen C. Roscow
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Executed **September 8, 2017**, at Rosemead, California.

/s/Alejandra Arzola
Alejandra Arzola
Program/Project Analyst
SOUTHERN CALIFORNIA EDISON COMPANY

8631 Rush Street
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CPUC Home

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

PROCEEDING: A1609001 - EDISON - FOR AUTHORI
FILER: SOUTHERN CALIFORNIA EDISON COMPANY
LIST NAME: LIST
LAST CHANGED: SEPTEMBER 8, 2017

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Back to Service Lists Index

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