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Exhibit No.: SCE-02, Vol. 4, Part 2
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C. Meissner



(U 338-E)

2021 General Rate Case

Load Growth, Transmission Projects and Engineering

Before the

Public Utilities Commission of the State of California

Rosemead, California
August 30, 2019

SCE-02, Vol. 4, Part 2: Load Growth, Transmission Projects and Engineering

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I.

INTRODUCTION

A. Content and Organization of Volume

The capital expenditures required to support load and DER growth, transmission grid reliability, and renewable generation are included in this part of the System Augmentation Volume. Additionally, the Engineering O&M that supports these activities are captured within this testimony. Because of the differences in design and operation of the transmission, subtransmission, and distribution systems, each system is covered under a separate planning process. The upgrades, modifications, and additions to the distribution and subtransmission systems are captured in the Load Growth Chapter of this volume. The upgrades, modifications, and additions to the transmission system are covered within the Transmission Projects Chapter. Collectively, the capital expenditures necessary to plan for the near- and long-term changes on the system are:

- Distribution Substation Plan;
- DER-Driven Grid Reinforcement;
- Transmission Substation Plan;
- System Improvement Programs;
- Various Rights of Way (Land Rights Management);
- Grid Reliability Transmission Projects; and
- Renewable Transmission Projects.

The Grid Engineering O&M supports projects, activities, and studies across all voltage classes of SCE's power system. Load Side Support O&M addresses customer concerns with power quality.

Part 2 of the System Augmentation testimony is composed of the following Business Planning Elements (BPEs):

- Load Growth
- Transmission Projects
- Engineering

Each chapter includes analyses for each BPE of: (1) regulatory and compliance requirements, (2) operation and maintenance (O&M) and capital funding authorized in the 2018 General Rate Case (GRC) compared to recorded amounts in 2018, (3) the 2021 O&M Test Year forecast relative to historical spending, and (4) the 2019 – 2023 capital expenditure forecast.

B. Summary of O&M and Capital Request

Volume 4, System Augmentation, presents SCE’s total requests for the System Augmentation BPG of \$35 million (constant 2018 dollars) in O&M expenses for 2021 Test Year and \$6.923 billion in capital expenditures for 2019 – 2023, and are presented in Figure I-1 and Figure I-2.

Figure I-1
System Augmentation Part 2 O&M Expenses 2021 Forecast
(Constant 2018 \$Millions)

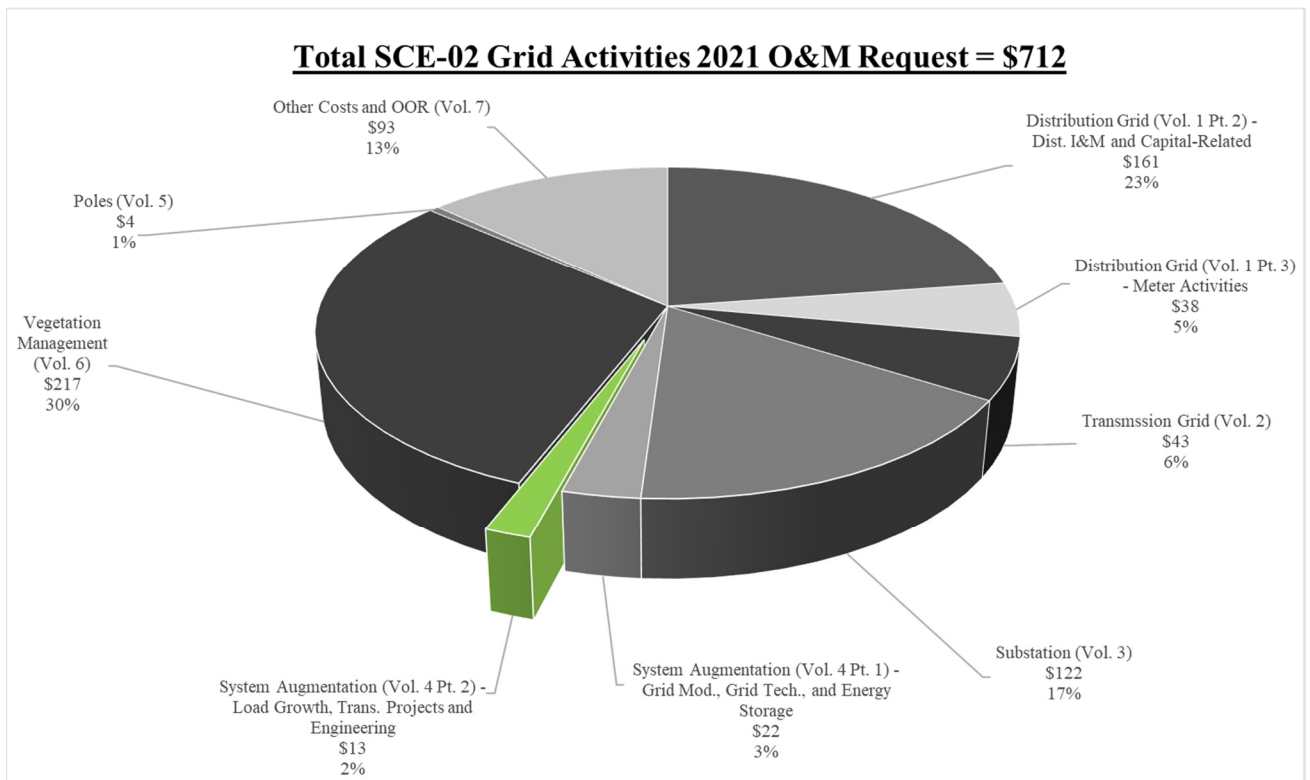
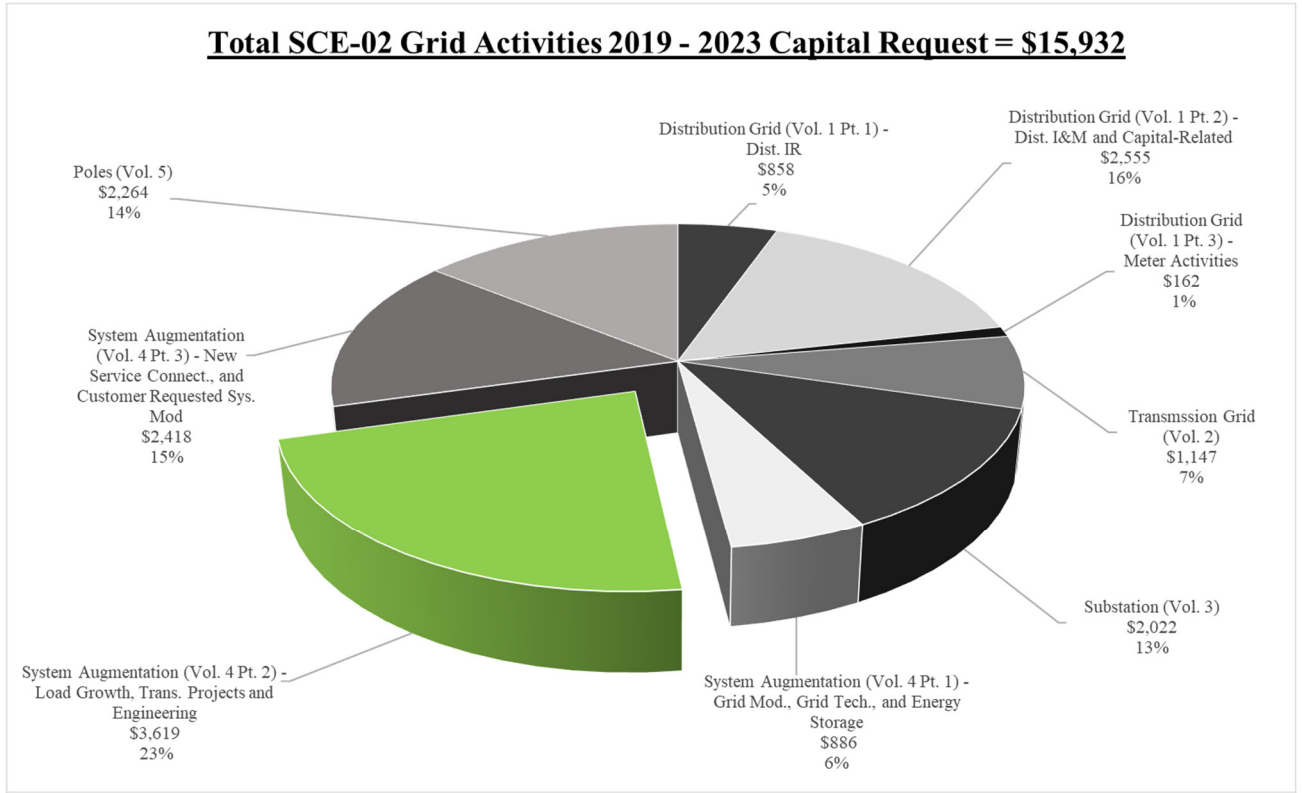


Figure I-2
System Augmentation Part 2 Capital Expenditures 2019-2023
(Total Company – Nominal \$Million)



1 SCE’s requests for System Augmentation Part 2 include \$12.8 million (constant 2018 dollars) in
2 O&M expenses for the 2021 Test Year and \$3.619 billion in capital expenditures for 2019-2023 for
3 Load Growth, Transmission Projects and Engineering BPEs.

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II.

LOAD GROWTH

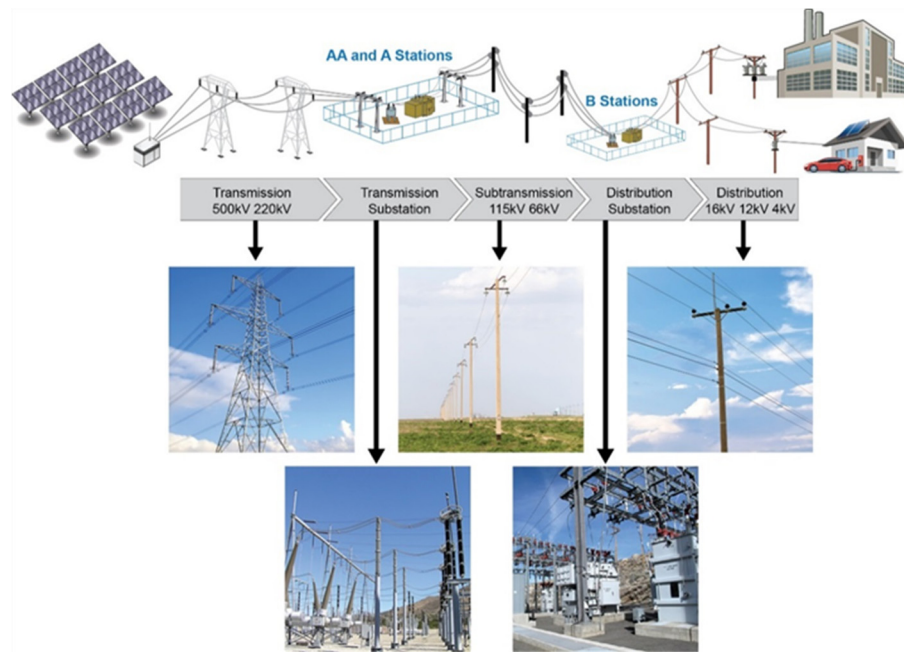
A. Overview

SCE’s Load Growth Business Plan Element (BPE) covers work needed to support customer load and Distributed Energy Resource (“DER”)¹ growth throughout SCE’s electrical grid. Because of the differences in design and operation of the transmission, subtransmission, and distribution systems, each system is planned for under a separate planning process. The distribution and subtransmission planning processes are detailed in this Load Growth testimony, while the transmission planning process is covered later in Chapter III, Transmission Projects.

Each year, SCE develops transmission, subtransmission, and distribution system plans that describe the projects and programs required to expand, upgrade, and reconfigure the electrical grid over the next 10 years. The term “grid,” as shown in Figure II-3 below, refers to the infrastructure comprised generally of transmission lines, subtransmission lines, substations, distribution circuits, and critical equipment such as circuit breakers, relays, substation transformers, conductors, and automation apparatus.

¹ DERs can include energy efficiency, energy storage, demand response, electric vehicles, and distributed generation.

*Figure II-3
Electrical Grid – Power System Overview*



1 SCE has presented its power system planning process in the past several GRCs. Though the
2 planning process has been refined over the past several decades, the overall driver of system
3 modification remains the same—to reliably accommodate increasing system capacity needs (resulting
4 from new customers or increased load from existing customers), while maintaining system reliability.
5 In addition, other drivers such as DER integration require additional grid reinforcements.

6 SCE plans for new infrastructure, modifications, or upgrades by considering multiple drivers to
7 find an overall least-cost, best-fit preferred solution. Alternative solutions are evaluated to make cost-
8 effective choices, and SCE evaluates system needs through a progression of potential solutions to solve
9 system needs within reason. That progression is explained in more detail later in Section II.C.2.
10 This GRC application also includes new regulatory requirements for Load Growth that are discussed in
11 the next section and new public safety priorities discussed by Mr. Kevin Payne in SCE-01, Volume 1.
12 The impacts of these factors are incorporated into all of the Capital Expenditures requested in this
13 chapter.

14 **1. Regulatory Background/Policies Driving SCE’s Request**

15 SCE must evaluate distribution system customer needs, analyze its system, and present
16 proposals to the Commission for approval to meet those anticipated demands.

1 This GRC, SCE’s Load Growth capital expenditures are directly influenced by Track 3 of
2 the Distribution Resources Plan (DRP). Track 3 of the DRP is divided into three Sub tracks, and this
3 Load Growth testimony satisfies certain compliance requirements within Sub track 1: Growth Scenarios
4 and Sub track 3: Distribution Investment Deferral Framework (DIDF).

5 Sub track 1 focuses on DER adoption and distribution load forecasting.
6 Considerations include disaggregation methodologies and data sources for distribution-level forecasting.
7 Consistent with DRP guidance, SCE’s planning process, as reflected in Section C.1.a), starts with the
8 California Energy Commission’s Integrated Energy Policy Report (IEPR) California Energy Demand
9 2017 Forecast.²

10 Sub track 3 aims to integrate the DRP into planning and cost recovery processes by
11 identifying opportunities for DERs to cost effectively defer or avoid traditional investor owned utility
12 (IOU) investments. As described in Section II.C.2.a), SCE annually publishes the first five years of
13 system needs and identified projects in the Grid Needs Assessment (GNA) report and Distribution
14 Deferral Opportunity Report (DDOR) respectively as required in the DRP.

15 **2. Compliance Requirements**

16 **a) 2015 GRC Decision (D.15-11-021)**

17 In the 2015 GRC Decision, the Commission directed SCE to “provide clear unit
18 cost forecast information for the major types of equipment...so that the total cost forecast for the project
19 or program can be compared to the sum of the unit costs.”³ Consistent with this requirement, SCE has
20 included the detailed unit cost and number of units required for the major types of equipment in
21 workpapers. Unit costs can vary between projects and programs as shown in the workpapers.

22 The Commission also directed SCE to “provide analysis of the preemptive [circuit
23 breaker] replacements in combination with other types of replacements.”⁴ In SCE-02, Vol. 3, SCE
24 describes the circuit breaker infrastructure replacement program, which identifies bulk power circuit
25 breakers and distribution circuit breakers approaching the end of their service lives that will need
26 replacement. In that testimony, SCE presents an analysis of these preemptive circuit breaker
27 replacements. When SCE identifies circuit breakers to be replaced under infrastructure replacement,

² Available at: https://www.energy.ca.gov/2017_energypolicy/documents/#demand, as of August 14 2019.

³ D.15-11-021.

⁴ D.15-11-021, p. 80.

1 those breakers are itemized by substation. The Substation Equipment Replacement Program (SERP),
2 described in Section II.D.4.d) of this volume, upgrades substation circuit breakers projected to exceed
3 short circuit duty interrupting capabilities. Under this program, SCE performs fault duty studies that
4 identify circuit breakers that must be upgraded to effectively and safely interrupt the fault current at a
5 substation. The forecast for this program includes only those breakers not already identified as part of
6 circuit breaker infrastructure replacement in SCE-02, Vol. 3.

7 **b) Distribution Resource Plan Track 3: Policy Issues (D.18-02-004)**⁵

8 **(1) Sub track 1: Growth Scenarios**

9 DRP Track 3, Sub track 1 mandates that the “Integrated Energy Policy
10 Report (IEPR) demand forecast will be adopted with updated Distributed Energy Resources (DER)
11 forecasts in January 2018,” beginning with the “2018-2019 distribution planning cycle.”⁶ To accomplish
12 this, the IOUs develop and “vet disaggregation methods though the Growth Scenario Working Group
13 and incorporate best practices in their planning processes.”⁷ Section II.C.1.a) describes SCE’s
14 methodology for adopting the IEPR demand forecast as the load growth forecast at the system level,
15 with additional details on the disaggregation methodologies described in the Distribution Forecasting
16 Working Group (DFWG) Final Report.⁸

17 **(2) Sub track 3: Distribution Infrastructure Deferral Framework (DIDF)**

18 The October 21, 2016 Assigned Commissioner’s Ruling on Track 3 Issues
19 finalized the scope of Track 3, Sub track 3 of the DRP to (1) establish a process to identify opportunities
20 for DERs to defer or avoid traditional infrastructure projects, (2) establish a process for utilities to seek
21 authorization and cost recovery for DER sourcing to enable deferral or avoidance of traditional grid
22 infrastructure investments, and (3) consider a process to ensure savings from deferred or avoided
23 distribution investments are accurately reflected in relevant GRC filings.⁹ As part of the DIDF,
24 D.18-02-004 orders the IOUs to file two reports on an annual basis that are key components to achieving

⁵ Sub Track #2 focuses on Grid Modernization investments and are covered in the Grid Modernization Chapter in SCE-04 Vol. 4 Pt. 1.

⁶ D.18-02-004, Ordering Paragraph 1.a., p. 2.

⁷ D.18-02-004, Ordering Paragraph 1.c., p. 2.

⁸ R.14-08-013.

⁹ Assigned Commissioner’s Ruling, dated October 21, 2016, in R.13-08-013.

1 the Commission’s objective to defer traditional infrastructure investments by competitively sourced
2 DERs. The Grid Needs Assessment (GNA) summarizes the forecasted deficiencies across the
3 distribution system related to capacity, reliability (back-tie), voltage, reactive power, resiliency
4 (microgrid), or a combination of services. The Distribution Deferral Opportunity Report (DDOR)
5 summarizes the traditional infrastructure investments that SCE has identified to mitigate the deficiencies
6 in the GNA. Section II.C.4, and Section II.C.2 describes SCE’s process for providing both the GNA
7 report and DDOR on an annual basis, along with details on how SCE maximizes asset utilization to
8 achieve the least-cost solution for projects.

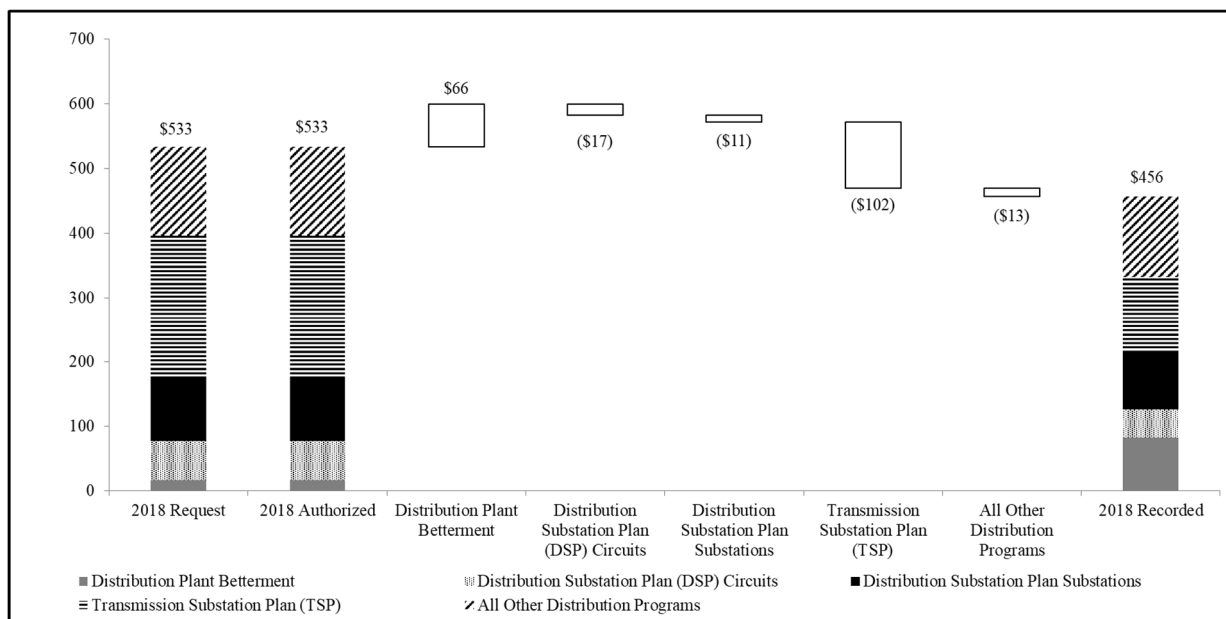
9 **B. 2018 Decision**

10 **1. Comparison of Authorized 2018 to Recorded**

11 The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the
12 recorded amounts;¹⁰ Figure II-4 below compares amounts for capital expenditures.

¹⁰ D.19-05-020, Ordering Paragraph 22, pp. 441-442.

Figure II-4
Load Growth
2018 GRC Authorized Variance Summary 2018 Capital¹¹
(Total Company– Constant 2018\$ Millions)



1 The variance in 2018 for Distribution Plant Betterment is explained in Section II.D.4.a).
2 SCE’s Grid Resiliency efforts recorded to Plant Betterment in 2018 before an official program was
3 established.

4 The 2018 expenditures in Distribution Substation Plan (DSP) Circuits are below
5 authorized levels largely due to a delay in the construction of the Safari Substation and pending permits,
6 including railroad-related permits. Additionally, SCE expenditures are lower than authorized because of
7 resource constraints accommodating Grid Resiliency efforts and construction delays due to permitting.

8 The 2018 expenditures were less than authorized for Transmission Substation Plan (TSP)
9 due to delays in several projects. For example, Johanna substation experienced delays resulting from an
10 RV park condemnation process. Approximately \$65M (including FERC and CPUC jurisdictional costs)

¹¹ Refer to WP SCE-07 Vol. 01 – Capital Authorized to Recorded. Note: *All Other Distribution Programs includes: 4 kV Cutovers - Load Growth Driven, Distribution Circuit Upgrades, Distribution Volt VAR Control and Capacitor Automation Program, Grid Reliability Projects, Land Rights Management, New Capacitors, Substation Equipment Replacement Program, and Substation Load Information Monitoring System.*

1 is related to Alberhill, for which the CPUC issued a decision to deny the Certificate of Public
2 Convenience and Necessity (CPCN) in August 2018. The remaining underrun is primarily due to lower
3 load growth affecting deferral or cancellation of Transmission Substation Plan projects.

4 **C. Distribution & Subtransmission Planning Process**

5 **1. Development of Load & DER Forecasts**

6 The first step in SCE's distribution and subtransmission planning process is to develop
7 peak load and DER forecasts for all distribution circuits, distribution substations, subtransmission lines,
8 and load-serving transmission substations. These forecasts span 10 years and include expected customer
9 load and DER growth.

10 Traditionally, SCE annually evaluates peak load conditions to determine the impacts to
11 SCE's distribution and subtransmission systems over a 10-year horizon. With increasing DER
12 penetration on the distribution system, the traditional peak load studies are not able to capture criteria
13 violations due to the DERs that could arise outside of the peak hours. As such, SCE now also evaluates
14 high DER output conditions and the mitigations necessary to address criteria violations. The planning
15 process for peak load and high DER output conditions are described in more detail throughout this
16 section.

17 **a) Development of Load Growth Forecast**

18 For both peak load and high DER output scenarios, SCE begins by developing a
19 10-year load growth forecast at the distribution circuit level. Pursuant to Commission guidance in the
20 DRP, this load growth forecast is established through the disaggregation of the California Energy
21 Commission (CEC) Integrated Energy Policy Report (IEPR) load growth forecast.¹² The CEC provides
22 this forecast to SCE, at the system-wide level, and not with the granularity necessary to account for
23 localized electrical needs on the distribution and subtransmission systems. SCE and other stakeholders
24 participate in the Distribution Forecasting Working Group (DFWG) to discuss and develop load and
25 DER methodologies to disaggregate system-wide forecasts to the distribution circuit level. "SCE also
26 incorporates additional load growth that may not have been fully reflected in the CEC forecast

¹² The process by which SCE develops this forecast is detailed in SCE's 2019 Grid Needs Assessment (GNA) filed in Rulemaking (R.)14-08-013 on August 15, 2019. Due to the close proximity of filing dates for the GNA and this 2021 GRC, SCE will provide the relevant sections of the GNA as a supplemental workpaper to this testimony when available. Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 364 - 365 – SCE's Grid Needs Assessment Narrative.

1 (e.g. cultivation load growth not in the 2016 IEPR),”¹³ which SCE considers incremental¹⁴ to the IEPR
2 forecast.

3 SCE’s disaggregation methodology of the IEPR forecast encompasses specific
4 local-area knowledge from the system planning engineers on developers’ new projects, as well as
5 econometric data relative to each planning area. Local-area knowledge is derived from SCE’s system
6 planning engineers working closely with developers of agricultural, commercial, industrial, and
7 residential projects to understand the electrical needs of these developers’ projects, timing of the
8 projects, and the projected increases in demand that would be placed on SCE’s distribution facilities in
9 the area. These projected demand increases are based on information provided by the developers, as well
10 as institutional knowledge from SCE’s past experiences with similar developments, and are added into
11 the IEPR forecast, resulting in an SCE load growth forecast.

12 **b) Incorporation of DERs That Produce and Consume Energy**

13 Along with the development of a load growth forecast, SCE incorporates forecasts
14 that account for other load-modifying inputs such as DERs, including energy efficiency, energy storage,
15 demand response, Plug-in Electric Vehicles (PEVs), and distributed generation (DG), such as solar
16 photovoltaic (PV) systems. SCE utilizes the CEC-developed IEPR forecasts for these load-modifying
17 inputs and disaggregates them to the distribution circuit level. In some cases, these inputs can reduce
18 aggregate load (although not necessarily peak demands on certain circuits), while in other cases, they
19 may increase aggregate load.

20 For PV included in the 10-year forecast (2019-2028), SCE has incorporated an
21 updated methodology¹⁵ for representing the impacts (*i.e.*, reductions) to peak load demand. This change
22 in methodology represents SCE’s adoption of an increase in the amount of solar PV output that is
23 considered “dependable” and can be relied upon for planning purposes, also known as “solar PV
24 dependability.” The updated dependable output values are based on (1) a cross-sectional analysis of
25 historical PV outputs for each hour of the day within a discrete operating region of SCE’s territory and

¹³ R.14-08-013, Appendix A, p. 97.

¹⁴ SCE considers Cultivation, Light Electric Vehicle (LEV) Superchargers, Mega Tract Homes, and Agricultural Pump Loads as incremental to the CEC 2017 IEPR forecast.

¹⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 4 – 13 – SCE’s Dependable Photovoltaic Generation Methodology.

1 (2) the regional output percentage for each hour empirically-derived from the 10th percentile of each
2 cross-section's data set.

3 Previous analysis, filed with SCE's 2018 GRC, calculated that 19% of the
4 installed nameplate value of solar PV could be considered "dependable" for planning purposes at 12:00
5 PM. The dependable output at 5:00 PM (when the SCE system peak is expected to occur), would result
6 in 2% of the total of installed solar PV considered as dependable and could be used to "offset" load for
7 planning purposes.

8 Since the time of peak for each of SCE's distribution circuits and substations
9 varies, SCE has continued to evaluate and refine its methodology for determining what the expected
10 maximum dependable solar PV output is. As an example of the updated methodology, 45% of the
11 installed nameplate of solar PV can be considered dependable at 12:00 PM for the San Jacinto region¹⁶
12 and 11.6% at 5:00 PM. SCE developed multiple regional-specific PV dependability curves in order to
13 represent factors such as local climate conditions in the forecasted PV performance output. SCE's
14 updated methodology applied to the 10-year forecast results in a greater amount of solar PV output
15 considered dependable for planning purposes, an increase in the load-modifying impacts, and a
16 corresponding decrease in net load growth.

17 Once the DER forecast is developed and applied, the result is a forecast of peak
18 load and DER conditions developed for the planning activities initially associated with distribution
19 circuits and distribution substations, which then serves as the input necessary to perform the planning
20 activities associated with subtransmission lines and load-serving transmission substations.
21 This forecasting methodology is the basis of SCE's DSP, Subtransmission Lines Plan (STL), and
22 Transmission Substation Plan (including the A-bank Plan and Subtransmission VAR Plan).

23 **c) Use of Forecasts for Peak Load versus High DER Analysis**

24 The Load and DER forecasts described above are the basis for both peak load and
25 high DER output analysis. For peak load analysis, SCE utilizes the forecasted peak load and
26 incorporates dependable DER output¹⁷ at the time of the peak load condition. For DER analysis, SCE
27 evaluates multiple conditions through its planning processes. Since PV is currently the largest DER

¹⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 4 – 13 – SCE's Dependable Photovoltaic Generation Methodology. All regions are tabulated in the WP.

¹⁷ SCE only includes dependable PV output, as described in Section C.1.b), as part of the peak load analysis.

1 driving potential violations with conditions such as “reverse power flow,”¹⁸ high DER forecasts
2 currently focus on daytime hours.¹⁹ Each distribution feeder has a different minimum load level during
3 those hours or “minimum daytime loading;” therefore, selecting a single hour to analyze for all of the
4 distribution system would not fully capture all DER-driven criteria violations that may arise due to
5 different feeder behavior and types of customers on different circuits. The study process analyzes the
6 potential violations that would likely occur throughout different hours of the day, on different days, and
7 throughout the years that were studied.²⁰ The other difference from the peak load analyses is that the
8 output curves were further broken down into monthly curves for each region and 95th percentile was
9 used.²¹ Identifying the criteria violations that are expected to occur under high DER output conditions is
10 necessary for SCE to plan for these conditions to reliably integrate DERs. For comparison, the San
11 Jacinto region in July, 74% of nameplate would be evaluated for impacts at 12:00 PM and 14% of
12 nameplate at 5:00 PM.²² Further, this study process incorporates analysis of different types of DERs and
13 their respective profiles.

14 **2. Proposed Solution Identification**

15 After the load and DER forecasts are developed, the next step in SCE’s planning
16 processes is to perform the necessary technical studies that determine whether the projected forecasts
17 can be accommodated using existing distribution, subtransmission, and transmission facilities. SCE uses
18 planning criteria as the basis for designing a reliable system. The planning criteria is based on equipment
19 loading limits (termed “planned loading limits”) that consider the effects of loading on thermal, voltage,
20 and protection limits under normal and emergency conditions. The analysis includes comparing the

¹⁸ “Reverse power flow” occurs when generation on a distribution circuit exceeds the amount of load on that circuit and causes power to flow into a distribution substation instead of towards customers as originally designed.

¹⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

²⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 – 29 – Details of the 8760 analysis are in the High Distributed Energy Resources Planning Assumptions.

²¹ SCE uses the 95th percentile as referenced in the Integration Capacity Analysis Working Group’s Final ICA WG Long Term Refinements Report. Available at: <https://drpwg.org/wp-content/uploads/2018/01/ICA-WG-LTR-Report-Final.pdf>, as of August 14, 2019.

²² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 – 29 – A sample monthly output curve is in High Distributed Energy Resources Planning Assumptions.

1 expected forecast peak load under peak heat storm conditions over a 10-year period to these established
2 planned loading limits.

3 When studies show that peak load or DER impacts are expected to exceed planned
4 loading limits, potential solutions are identified to mitigate the risk of overloading equipment, which in
5 turn serves to decrease the probability of failures and service interruptions that might affect many
6 customers. As part of identifying solution alternatives, SCE first seeks to maximize the utilization of
7 existing assets before developing projects that require capital expenditures to install new infrastructure.
8 The forecast costs, for solutions requiring new infrastructure over this GRC period, are found in Section
9 II.D.

10 a) **Distribution Substation Plan (DSP)**

11 During the planning process for the distribution system, SCE performs analyses of
12 system performance to identify system issues throughout the 10-year planning horizon that need to be
13 addressed. The first five years of these system needs are identified in SCE's annually published Grid
14 Needs Assessment (GNA) report as required by the Commission in the DRP.²³ SCE also performs
15 analyses to evaluate solutions to address the identified system needs throughout the ten-year planning
16 horizon, which seek to maximize asset utilization and achieve the least-cost solutions to meet the
17 electrical needs of its customers. The projects identified within the first five years are then included in
18 SCE's annually published Distribution Deferral Opportunities Report (DDOR) as also required in the
19 DRP. Further information on the GNA and DDOR reports can be found in Grid Modernization
20 Compliance Requirements in SCE-02 Volume 4 Part 1.

21 SCE's prioritization of solution alternatives for the Distribution Substation Plan
22 begins with evaluating the lowest cost alternatives first, and then sequentially reviewing the following
23 potential solutions:

- 24 • Maximizing equipment utilization;
- 25 • Distribution circuit upgrades;
- 26 • New distribution circuits;
- 27 • Substation expansion; and
- 28 • New substations.

²³ D.18-02-004, on Track 3 Policy Issues, Sub Track #1 (Growth Scenarios) and Sub Track #3 (Distribution Investment and Deferral Process).

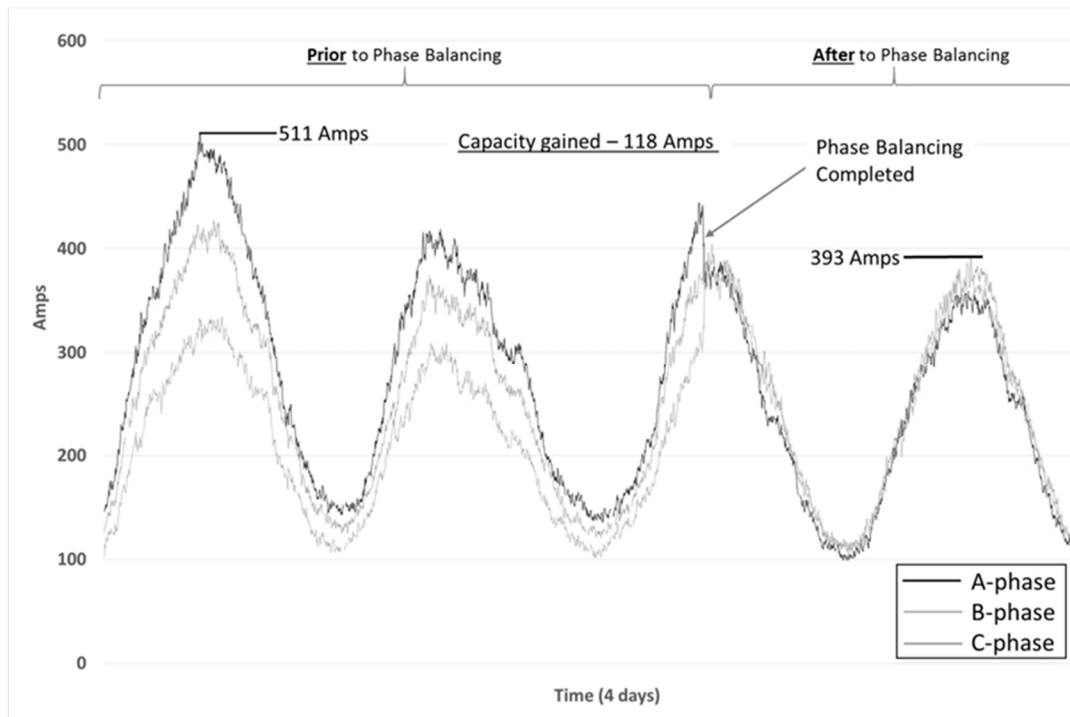
1 Throughout the progression, SCE develops a set of potential projects that can
2 address the forecast distribution system needs. The technical feasibility of each proposed alternative is
3 reviewed with various SCE stakeholders responsible for design, construction, and operation and
4 maintenance. SCE uses this stakeholder input, with reliability, operational flexibility, and cost-
5 effectiveness factors, to determine which projects are technically feasible and eliminates those which are
6 not. Of the solutions that remain, SCE then selects the most suitable project as the preferred solution to
7 carry forward. The project lists provided in Capital Expenditures – Load Growth, Section II.D, have
8 been evaluated in this sequential manner, demonstrating that the proposed projects best fit the needs of
9 the distribution system.

10 (1) **Maximize Equipment Utilization**

11 When SCE forecasts that load will exceed planned loading limits on a
12 distribution circuit or substation, the first step is to analyze solutions that are minor or can be solved by
13 operational changes – options that do not require additional infrastructure. SCE’s distribution system is a
14 three-phase power system capable of serving a variety of customer needs. Many loads on the system
15 require service from all three phases of a distribution circuit, such as large motors in commercial and
16 industrial facilities; while other loads on the system require only a single phase, such as a residential
17 home. As load is added to distribution circuits, attempts are made to do so in a manner which will result
18 in approximately equivalent amounts of load connected to each of the three phases of the circuit. It is
19 important to balance load across the three phases of distribution facilities because the highest loaded
20 phase determines the peak loading of the circuit for planning activities. When there is the potential to
21 reduce the loading on the highest-loaded phase by transferring some of the single-phase load from the
22 highest phase to another phase that is lower, SCE considers this solution first as it maximizes the use of
23 existing capacity without requiring additional infrastructure to be installed. This solution is termed
24 “phase balancing.”

25 Figure II-5 below shows an example of how the peak loading on a circuit
26 can be reduced by phase balancing. The figure shows two days of loading before balancing, one day
27 during the balancing process, and one day after the balancing has occurred. While phase balancing is
28 often a cost-effective solution, this may not always be the case depending on the particular system
29 characteristics, the load profiles of individual customers and DERs, and how and where they are
30 physically connected to the circuits.

Figure II-5
Circuit Load Phase Balancing



1 If phase balancing is not an available option, SCE analyzes potential
2 solutions that transfer load through switching to balance the load among the distribution circuits.
3 This load balancing activity involves using existing sectionalizing devices (e.g., switches located at
4 strategic locations along a circuit) to transfer a section of one circuit to an adjacent circuit.
5 Distribution circuits are designed to include switches (normally operated in the “closed” position
6 allowing power to flow through them) along the mainline of the circuit as well as having other switches
7 (normally operated in the “open” position not allowing power to flow through them) located at the ends
8 of the circuit at connection points to adjacent circuits. If neighboring facilities have sufficient reserve
9 capacity, and if infrastructure exists that tie the circuits and/or substations together, SCE will consider
10 performing load transfers through use of those facilities to reduce loading on the facilities that are
11 projected to have loading violations. In doing so, SCE maximizes use of existing capacity and
12 infrastructure. Phase balancing and load balancing are types of solutions that typically incur minimal to
13 no capital expense and often solve identified overloads by increasing the utilization of installed assets.

14 If existing infrastructure configurations cannot address the identified needs
15 through phase balancing or load balancing, the next option is to consider upgrades to installed facilities

1 or installation of new facilities to allow for the use of existing capacity reserves through the transfer of
2 load between distribution circuitry and substations. This option is covered in the next section addressing
3 distribution circuit upgrades.

4 (2) **Distribution Circuit Upgrades**

5 Within SCE's DSP planning process, if it is forecasted that any portion of
6 the distribution system is expected to exceed operating limits and if existing facilities cannot meet
7 system needs after evaluating phase balancing and load balancing alternatives, then projects to upgrade
8 distribution circuits are evaluated. The process begins by evaluating solutions that could provide
9 additional system capacity through upgrades to existing distribution circuits. While distribution circuit
10 upgrades most commonly address system issues, such as circuit-related capacity or reliability concerns,
11 they may also function to address distribution substation capacity concerns. Typical work includes
12 addressing loading or reliability issues through the installation of new switches, replacement of cables or
13 conductors with those of a higher capacity, or installing new cables or conductors to create circuit ties to
14 facilitate load transfers between circuits and substations. The expenditure forecast for this type of work
15 is presented in the Distribution Circuit Upgrade Section II.D.1.a).

16 (3) **New Distribution Circuits**

17 If a distribution circuit upgrade project is not expected to be able to meet
18 the need of a projected violation, or if the distribution circuit upgrade solution is economically
19 impractical and would not meet the long-term needs of the area, SCE then considers constructing new
20 distribution circuits. For example, if the average distribution circuit loading is projected to exceed
21 distribution planning criteria and guidelines, further analysis is performed to consider if multiple
22 existing distribution circuits in a general geographic area are forecast to reach or exceed capacity limits.
23 These considerations may result in the need for a new distribution circuit.²⁴

24 SCE constructs new distribution circuits as part of one of three types of
25 projects: (1) standalone projects, (2) substation capacity increase projects, and (3) new substation
26 projects. When the need for a new distribution circuit is identified to relieve load from other distribution
27 circuits, the proposed new capacity is planned to not only allow for the transfer of load from the highly

²⁴ As discussed previously, this type of work is only pursued after considering lower cost solutions including phase balancing, load balancing, and distribution circuit upgrades.

1 loaded existing circuits (in order to bring them to within acceptable planned loading limits), but also to
2 provide circuit ties to increase operational flexibility.

3 **(4) Substation Expansion Projects**

4 SCE strives to maximize the planned utilization across the system by first
5 designing distribution facilities to provide sufficient capacity and operational flexibility to allow for
6 reconfiguring of distribution circuits while balance loading across both the distribution circuits and
7 substations to accommodate serving customer demand under peak load conditions during both normal
8 and emergency system conditions.

9 If a distribution substation is projected to exceed its planning limits, and
10 due to capacity limitations at neighboring substations or because there are no solutions possible that
11 would involve load transfers to address the capacity deficits, a project to increase the capacity of a
12 substation may be the most cost-effective solution. These types of projects are identified as “substation
13 expansion projects” and may include such activities as installing new substation transformers, replacing
14 lower capacity substation transformers with ones of higher capacity, or replacing capacity-limiting
15 components. A substation expansion project is compared to other alternatives to ensure the most
16 economical project or combination of projects is selected to reliably meet the long-term needs of the
17 area. For example, it may be more economical to add capacity at a distribution substation, often in
18 combination with a new distribution circuit to offload a neighboring substation, instead of constructing a
19 new substation.

20 **(5) New Substation Projects**

21 In some instances, a project to construct a new substation is the most cost-
22 effective long-term solution. One example is if an addition of capacity to an existing substation through
23 either an upgrade of equipment within the existing substation property or through an expansion of the
24 substation property is not practical or feasible. Another is if multiple existing distribution substations in
25 the same geographic region are already constructed to their maximum design capacities and are
26 projected to experience continued load growth. A third is if a new development is being constructed in
27 an area either isolated from existing electrical facilities or where there is insufficient electrical
28 infrastructure. In each of the preceding examples, a new substation may prove to be the preferred
29 economical solution to address the long-term needs of the area when compared to other feasible
30 alternatives.

1 **b) Planning for DERs and the DER-driven Upgrades**

2 As described above in Section II.C.1.c), SCE analyzes high DER output
3 conditions to determine whether system upgrades are necessary to accommodate the growth of DERs.
4 The analysis includes the same planning thresholds, criteria, and practices as those used to evaluate peak
5 load conditions. This includes utilizing the same thermal loading, voltage, and protection limits of
6 distribution and substation equipment. Due to the nature and complexity of DERs in real-time, the
7 analysis also identifies areas with higher DER adoption, which can impact the ability for SCE’s grid
8 operators to effectively shift load under normal, emergency or contingency conditions. Similar to load
9 transfers, DERs need to be balanced across feeders to provide engineers and grid operators the necessary
10 level of operational flexibility.²⁵ Because of these impacts, SCE identifies circuits and substations with
11 higher DER penetration and identifies the required upgrades in order to maintain adequate reliability and
12 operational flexibility on an increasingly complex distribution grid.

13 **c) Subtransmission Planning and Transmission Substation Plan (TSP)**

14 After performing the planning activities for the Distribution Substation Plan and
15 developing the associated loading projections for each of the distribution substations, these values then
16 become the necessary inputs to perform the planning activities associated with SCE’s higher voltage
17 assets: transmission substations and SCE’s subtransmission lines and equipment as shown in Figure II-3.
18 The Transmission Substation Plan (TSP), which includes the Subtransmission Line Plan, the A-bank
19 Plan, and the Subtransmission VAR Plan,²⁶ captures the reliability needs of the higher voltage
20 substations and equipment.

21 Whereas the DSP uses the loading projected for the highest expected temperature
22 within a ten-year period, referred to as a one-in-ten year heat storm condition, the A-bank Plan and
23 Subtransmission VAR Plan use the loading expected for the highest expected temperature within a five-
24 year period, referred to as a one-in-five year heat storm condition. This is because Subtransmission and
25 Transmission networks and their facilities cover much larger geographic areas as compared to

²⁵ “Operational Flexibility” allows power system operators to respond in real-time to variations in load and system voltages to pre-emptively or reactively maintain system reliability.

²⁶ Volt-ampere reactive power (VAR) is the unit used to measure reactive power in alternating current electric systems. Because alternating current systems have varying voltage, these systems must vary the current with the voltage to maintain stability. VARs measure the lead or lag between synchronization of voltage and current.

1 distribution substations and there is a lower probability that the entire area, and each distribution
2 substation within that area, would experience the same extreme weather conditions at coincident times.
3 Conversely, because distribution substations serve smaller geographic areas, there is a higher probability
4 that several adjacent distribution substations may each experience similar extreme weather conditions at
5 coincident times, resulting in a reduction in the ability for adjacent distribution substations to provide
6 loading relief to each other. Thus while distribution substation planning requires a higher value of
7 capacity margin, the applicable criteria for the planning activities associated with the A-bank Plan and
8 Subtransmission VAR Plan allow for a reduction in the planning margins required to account for peak
9 loading.

10 (1) **Subtransmission Lines Plan**

11 Subtransmission lines operating at 66 kV or 115 kV deliver electricity
12 from the low-voltage side of SCE's transmission substation transformers to the distribution substations.
13 These subtransmission lines are interconnected together to form a network of lines that serve the
14 distribution substations. A networked configuration provides multiple pathways to the distribution
15 substations, which in turn increases the reliable delivery of power to the substations, allowing for the
16 system to provide continuity of service during both normal system conditions when all facilities are in-
17 service, and during abnormal system conditions when electrical facilities may be out-of-service due to
18 planned or unplanned outages.

19 The objective of the Subtransmission Lines Plan is to provide sufficient
20 66 kV or 115 kV subtransmission line capacity to serve the projected peak load of SCE's distribution
21 substations. Through power flow studies, the capacities of each subtransmission line are evaluated to
22 determine if they can be safely operated within established loading limits under normal conditions with
23 all facilities in service ("Base Case"), and under abnormal conditions when equipment is out of service
24 due to planned or unplanned outages ("Likely Contingency"). These power flow studies also evaluate
25 whether adequate voltage can be maintained under normal and abnormal conditions. When it is
26 projected that a subtransmission line will become overloaded or that it cannot maintain adequate
27 voltage, low-cost operational solutions are first considered, similar to the distribution planning process.
28 These include determining if existing infrastructure can be utilized to transfer customer load from
29 highly-loaded subtransmission lines to others with sufficient reserve capacity. Often this occurs through
30 load transfers from one distribution substation to another using distribution circuitry. If such a solution is
31 determined to be infeasible, a project may be initiated to expand, upgrade, or reinforce the

1 subtransmission system to address the identified issues. Typical projects include replacing existing
2 subtransmission conductors (“reconductoring”) with higher capacity conductors, replacing limiting
3 components such as switches or circuit breakers with those of higher capacities, constructing new
4 subtransmission lines, and/or installing 66 kV or 115 kV capacitor banks at distribution substations.

5 SCE’s subtransmission planning criteria and guidelines also provide
6 guidance on how many subtransmission lines are necessary to provide adequate reliability and power
7 delivery to each of the distribution substations depending on how much load is projected to be served.
8 Over time, as distribution substation load is projected to increase in an area, an additional
9 subtransmission line may need to be constructed to ensure sufficient capacity will be available under
10 peak load conditions and under normal and abnormal system conditions. When these conditions are
11 identified, SCE reviews the various available alternatives described above to select the most cost-
12 effective solution that meets the system loading needs while maintaining safe and reliable service.

13 **(2) A-bank Plan**

14 SCE’s load-serving substations that reduce voltage from the transmission
15 level (220 kV or 500 kV) to the subtransmission level (66 kV or 115 kV) are termed “A-bank”
16 substations. These substations function as the interface points in between the transmission system and
17 the generation units connected to it, and SCE’s subtransmission systems and distribution substations.
18 A-bank substations contain transformers that reduce transmission-level voltage (220 kV or 500 kV) to
19 lower levels (66kV or 115 kV) that are compatible with the subtransmission networks that provide
20 power to the distribution substations. SCE identifies any system-related issues and associated
21 mitigations in its annual A-bank Plan. The process is similar to SCE’s DSP; however, the A-bank Plan
22 reviews the 500/115 kV, 220/115 kV, and 220/66 kV A-bank substations over the ten-year planning
23 horizon. The purpose of the A-bank Plan is to identify potential transformer overload conditions and
24 voltage criteria violations to avoid the risk of loading beyond their capabilities. The consequences of
25 overloading these transformers could result in excessive degradation of transformer life or failures of the
26 transformer or other associated equipment that could result in service interruptions to customers. A-bank
27 substations commonly serve many distribution substations over widespread geographic areas. As they
28 act as the primary source of power to many distribution substations, the impact of power delivery can be
29 of much greater magnitude than that of distribution substations.

1 distribution system, an undesirable condition based on the need for voltage stability. Under worst case
2 conditions, voltage instability is mitigated by shedding load.

3 The objective of the Distribution VAR Plan is to fully supply the peak reactive
4 power needs of each of the distribution circuits under normal weather conditions; this means
5 maintaining unity power factor (zero reactive demand) at each distribution circuit. These reactive power
6 needs increase as load is added to distribution circuits. When a distribution circuit is forecast to have a
7 VAR deficiency, SCE will design a capital project to install either an overhead or pad mounted capacitor
8 bank on the circuit, depending on the circuit configuration.

9 **c) Distribution Volt VAR Control (DVVC)**

10 The Distribution Volt VAR Control (DVVC) Program centralizes control of the
11 field and substation capacitors to coordinate and optimize voltage and VARs across all distribution
12 circuits fed by a distribution substation. The DVVC program has several objectives: minimizing
13 1) system-wide voltage, 2) energy consumption, and 3) capacitor switching, while maintaining overall
14 customer Rule 227 service voltage requirements and operating within the local distribution field
15 Programmable Capacitor Controls (PCC) settings.

16 The DVVC is implemented at SCE as a centralized voltage and VAR control
17 scheme through the Distribution Management System (DMS) and the Energy Management System
18 (EMS), which controls the switching of existing capacitors in substations and on distribution circuits.

19 **d) Substation Equipment Replacement Program**

20 The Substation Equipment Replacement Program (SERP) evaluates the adequacy
21 of substation terminal equipment and system protection equipment, and proposes upgrades when
22 deficiencies are identified. The SERP identifies substations where available fault current, or short-circuit
23 duty, exceeds safe equipment ratings essential to the provision of safe, reliable service.

24 SCE's electrical distribution system is designed to safely detect and isolate faults.
25 Distribution system faults can be caused by natural events, equipment failures, or accidents caused by
26 human error. When a fault occurs, dangerous levels of current flow from all electrical sources to the
27 location of the fault. Due to the magnitude of fault current, a fault condition must be isolated quickly to
28 restore safe operating conditions to the electrical system. Not isolating a fault quickly enough can cause
29 major damage to distribution equipment, can cause catastrophic failure, and can seriously jeopardize

²⁷ Voltage as designated in the ANSI C84.1 standard and modified by California Rule 2.

1 public and employee safety. Substation circuit breakers are the most common devices used to isolate
2 faults and are relied upon to interrupt the highest fault currents experienced on the distribution system.
3 If they are incapable of interrupting expected fault currents, the circuit breaker(s) is/are likely to fail
4 when those faults occur. Such failures can be violent and result in widespread and prolonged outages.

5 **e) DER-driven Circuit Breaker Upgrades**

6 Similar to the Substation Equipment Replacement Program (SERP), SCE
7 evaluates the adequacy of substation terminal equipment and system protection equipment with the
8 increased short circuit current from DERs, and proposes upgrades when deficiencies are identified.

9 When a fault occurs near inverter-based resources such as DERs, higher levels of
10 current flow from all electrical sources (*i.e.* generators) to the location of the fault. SCE assumes the
11 level of fault contribution from DERs that is published in SCE's Integrated Capacity Analysis (ICA)²⁸ in
12 this analysis as opposed to SERP, which only considers fault contribution from generators connected at
13 the transmission and subtransmission voltage levels.

14 **4. Deferral Opportunities**

15 Pursuant to Commission guidance in the DRP, SCE annually publishes the projects
16 identified within the first five years that address the system needs in the Distribution Deferral
17 Opportunities Report (DDOR). This information, in conjunction with the Grid Needs Assessment
18 (GNA), provides data to the public to support competitive market participation to defer traditional
19 infrastructure investments via competitively sourced DERs. As further described in SCE-02 Volume 4
20 Part 1, Chapter II: Grid Modernization, the five Engineering and Planning (E&P) tools and GMS
21 collectively support the Commission's vision of deferring traditional wires solutions with DERs via the
22 DIDF.

23 **5. Implementation of Solutions**

24 Following the completion of each of the described planning processes and the
25 determination of the appropriate solutions to meet the system needs, the next step is to proceed with the
26 needed capital improvements. The implementation of the proposed solutions begins with internal
27 stakeholder review at various stages. Part of this review includes the coordination of work activities to
28 find efficiencies through coordinating construction activities, avoiding any duplicative or redundant
29 work with other programs, such as aging infrastructure replacement.

²⁸ See SCE-02, Vol. 4 Part 1 for description of ICA.

1 As an example, if it is determined that a preferred solution to meet a system capacity
2 need is to replace an older, smaller capacity substation transformer with one of a larger capacity, a
3 substation expansion project will be initiated. During the stakeholder review process it is reviewed and
4 determined that the same transformer has been identified for replacement due to review of aging
5 infrastructure. Each project's needs are evaluated and prioritized to determine which program would
6 support the replacement of the transformer, while the other program would cancel the duplicative scope.
7 This process exists to avoid unnecessary and overlapping work. Similar reviews occur across SCE's
8 various capital investment programs to ensure efficient and cost-effective projects are proposed.
9 These reviews occur annually as part of SCE's 10-year horizon planning processes.

10 **D. Capital Expenditures – Load Growth**

11 The Distribution and Subtransmission Planning Processes evaluate the system needs under load
12 and DER growth scenarios. The following capital expenditures are the result of SCE's solution
13 identification process but reduced to account for shifts in overall priorities for public safety as described
14 by Mr. Kevin Payne in SCE-01, Volume 1. The near-term and long-term reliability needs driven by load
15 and DER growth are still projected, however, SCE has adjusted the Load Growth capital expenditure
16 requests in this application to account for SCE's execution expectations and prioritization given the
17 resource constraints that the higher priority work poses.

18 For each Capital Expenditure in this section, SCE addresses any of the atypical variances that
19 may have recorded historically. It is important to note that due to the constraints mentioned and
20 compliance with DRP Track 3, Sub track 1 requirements listed in Section II.A.2.b)(1), the Capital
21 Expenditure forecasts will not necessarily trend with recorded costs for 2014-2018. SCE explains the
22 basis for each expenditure category in order to complement the justification for each category's purpose
23 and need.

24 SCE is forecast to spend \$1,638 million in total capital expenditures from 2019 – 2023, of which
25 \$1,539 million is CPUC-Jurisdictional. Table II-1 shows the total company (FERC and CPUC-
26 jurisdictional) capital expenditure summary and Table II-2 shows the CPUC-Jurisdictional capital
27 expenditures only.

Table II-1
Load Growth Capital Expenditure Summary
(Total Company – Nominal \$000)

Line No.	Program/Project Category	2019	2020	2021	2022	2023	Total
1	Distribution Substation Plan	\$199,876	\$262,086	\$183,857	\$103,258	\$92,716	\$841,792
2	DER-Driven Grid Reinforcement	\$0	\$512	\$42,523	\$22,788	\$27,677	\$93,500
3	Transmission Substation Plan	\$86,427	\$108,769	\$87,291	\$117,885	\$136,422	\$536,794
4	System Improvement Programs	\$45,440	\$41,258	\$46,806	\$16,893	\$12,182	\$162,579
5	Land Rights Management	\$580	\$599	\$633	\$652	\$671	\$3,135
6	Totals	\$332,323	\$413,224	\$361,109	\$261,476	\$269,668	\$1,637,800

Table II-2
Load Growth Capital Expenditure Summary
(CPUC Jurisdictional – Nominal \$000)

Line No.	Program/Project Category	2019	2020	2021	2022	2023	Total
1	Distribution Substation Plan	\$199,876	\$262,086	\$183,857	\$103,258	\$92,716	\$841,792
2	DER-Driven Grid Reinforcement	\$0	\$512	\$42,523	\$22,788	\$27,677	\$93,500
3	Transmission Substation Plan	\$83,657	\$107,787	\$86,243	\$88,011	\$72,277	\$437,975
4	System Improvement Programs	\$45,440	\$41,258	\$46,806	\$16,893	\$12,182	\$162,579
5	Land Rights Management	\$580	\$599	\$633	\$652	\$671	\$3,135
6	Totals	\$329,553	\$412,242	\$360,061	\$231,602	\$205,523	\$1,538,981

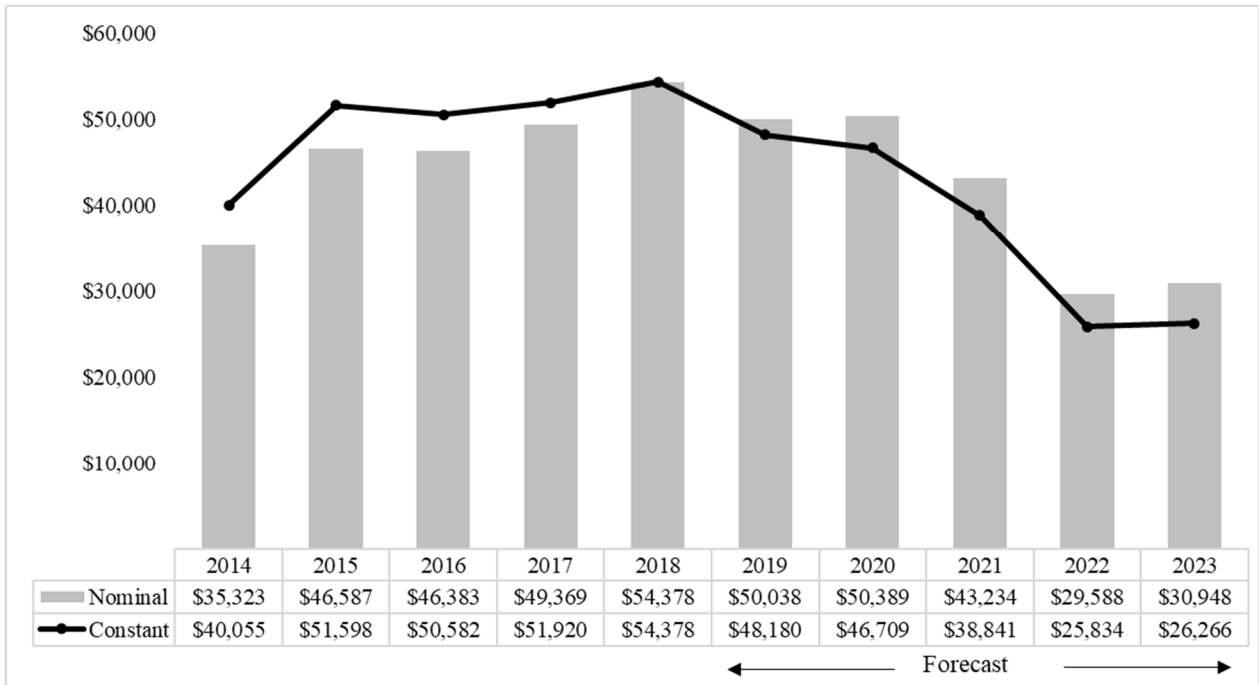
1. Distribution Substation Plan

As detailed in earlier sections, the outcome of SCE’s distribution planning process is the coordinated set of solutions to address expected distribution system needs due to load growth and customer changes in load type and behavior. After existing equipment is evaluated for opportunities to solve distribution needs, the set of infrastructure solutions resulting from the progression described in Section II.C.2.a) are covered in more detail here.

1 a) **Distribution Circuit Upgrades**

2 Figure II-6 below shows 2014–2018 recorded and 2019–2023 forecast capital
 3 expenditures for Distribution Circuit Upgrades.

Figure II-6
Distribution Circuit Upgrades Capital Expenditure Summary
WBS Element CET-ET-LG-PF²⁹
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



4 **(1) Program Description and Need for Program**

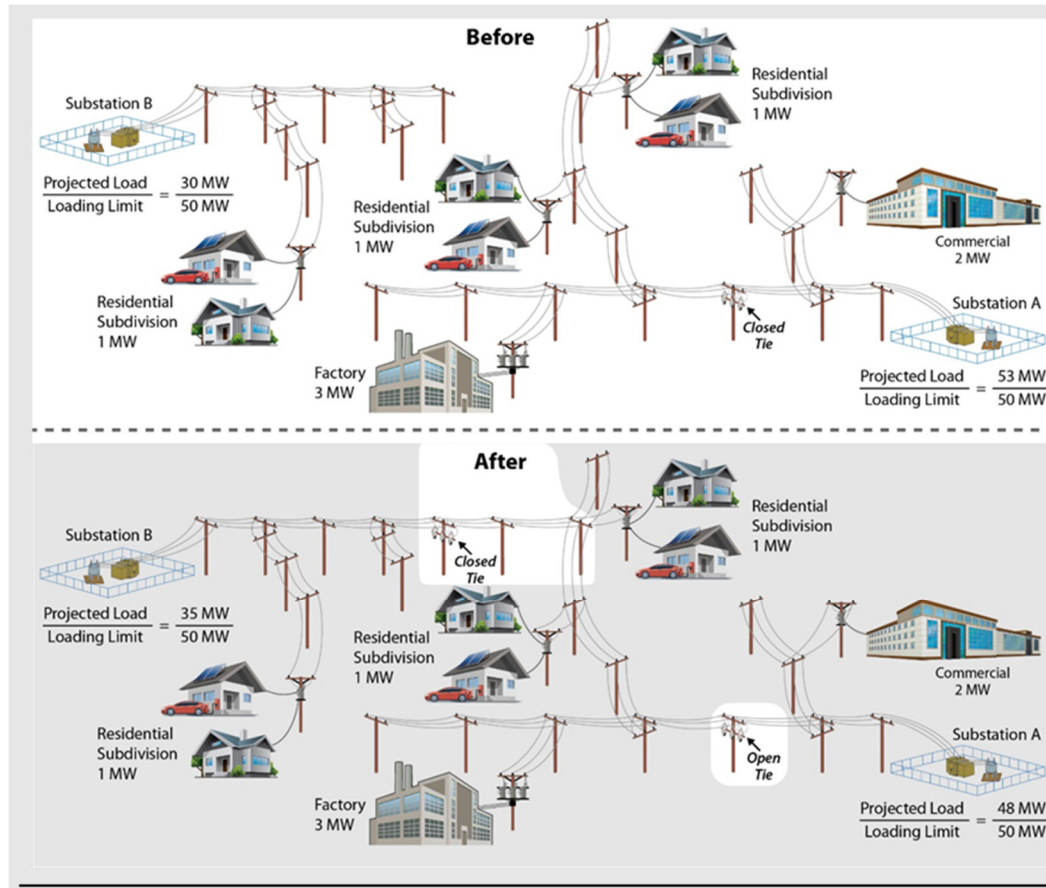
5 The Distribution Circuit Upgrades program covers forecast expenditures
 6 for work outside of the substation required to relieve heavily loaded distribution circuits and substations
 7 expected to exceed distribution planning criteria limits. This includes all work required on distribution
 8 circuits to solve distribution needs. This work enables distribution circuits to carry more electric current
 9 and/or make necessary transfers between distribution circuits and substations to mitigate situations
 10 where equipment is forecast to exceed capacity limits. Typical work includes installing new switches,

²⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 30 – 31 – Capital Detail by WBS Element for Distribution Circuit Upgrades.

1 upgrading cable or conductor, or installing new conductor to create circuit ties to facilitate load transfers
2 between substations and circuits.

3 As an example, if Substation A is forecast to exceed its installed capacity
4 and neighboring Substation B has capacity in reserve, but no circuit ties between the two exist or if
5 circuit ties do exist but are not of sufficient capacity, a distribution circuit upgrade may be proposed to
6 either create a circuit tie or to upgrade the capacity of existing facilities to allow for load transfers from
7 Substation A to Substation B. This upgrade and associated load transfer would serve to lower the
8 loading of Substation A to within its capacity limits by utilizing existing capacity reserves of Substation
9 B. This scenario is depicted in Figure II-7.

Figure II-7
Distribution Circuit Upgrade Relieving Substation Capacity Limitation



10 In Figure II-7 before any upgrade or load transfer, Substation A is shown
11 to be overloaded by 3 MW, while Substation B has 20 MW of reserve capacity. By adding a circuit tie

1 between Substations A and B, the projected overload condition of Substation A can be remedied by
2 utilizing the existing reserve capacity of Substation B, thus avoiding a substation upgrade project.

3 In some cases, distribution circuit upgrades are necessary to address issues
4 that result from the high loading of multiple distribution circuits which share common underground
5 facilities. Underground conduit systems are comprised of concrete-encased conduits and underground
6 structures such as vaults or manholes. Heat dissipation is a significant issue that impacts underground
7 facilities. As loading levels increase, so does the heat that the conductors emit. The operational capacity
8 of a conductor is directly correlated with the temperature of the environment that the conductor is
9 operated in. When multiple distribution circuits are in common underground structures, each contribute
10 to the collective temperature. To prevent equipment damage or failure, temperatures must be maintained
11 to within equipment specifications, and this can result in the need to reduce the individual loading
12 capabilities of each of the circuits. To avoid the loss in capacity and to maintain safe and reliable
13 operating conditions, distribution circuit upgrades may be proposed to reconfigure underground conduit
14 systems to reduce the number of circuits sharing structures, thereby producing a corresponding reduction
15 in the operating temperature of the equipment. Reconfiguration of underground facilities can include
16 installing additional conduits in separate duct banks and then rerouting distribution circuits, installing
17 additional vaults or manholes, or replacing underground cables with those of higher capacity. In this
18 manner, distribution circuit upgrades may serve to address capacity and reliability issues specifically
19 associated with underground distribution facilities.

20 (2) **Basis for Capital Expenditure Forecast**

21 Figure II-6 above summarizes recorded costs for the 2014–2018 period for
22 the Distribution Circuit Upgrades category, and forecast expenditures for the 2019–2023 period.

23 The total forecast cost for the 2019–2023 period is \$204.20 million (in nominal dollars). From 2014–
24 2018, SCE’s expenditures on this program averaged approximately \$49.7 million per year (in constant
25 2018 dollars). The forecast for 2019-2023 averages to \$37.2 million per year (in constant 2018 dollars).

26 Figure II-6 provides the forecast expenditures for 2019 & 2020 which are
27 based on scoped work. For 2021-2023, SCE uses a growth ratio³⁰ to calculate the proportion of capital
28 expenditure needed in a year relative to the forecast load growth in that year. The growth ratio is

³⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 32 – 33 – Distribution Circuit Upgrades Forecast Methodology.

1 calculated for each year using two key variables: 1) the costs of completed or planned distribution circuit
2 upgrades from a given year and 2) its corresponding load growth assumption.³¹

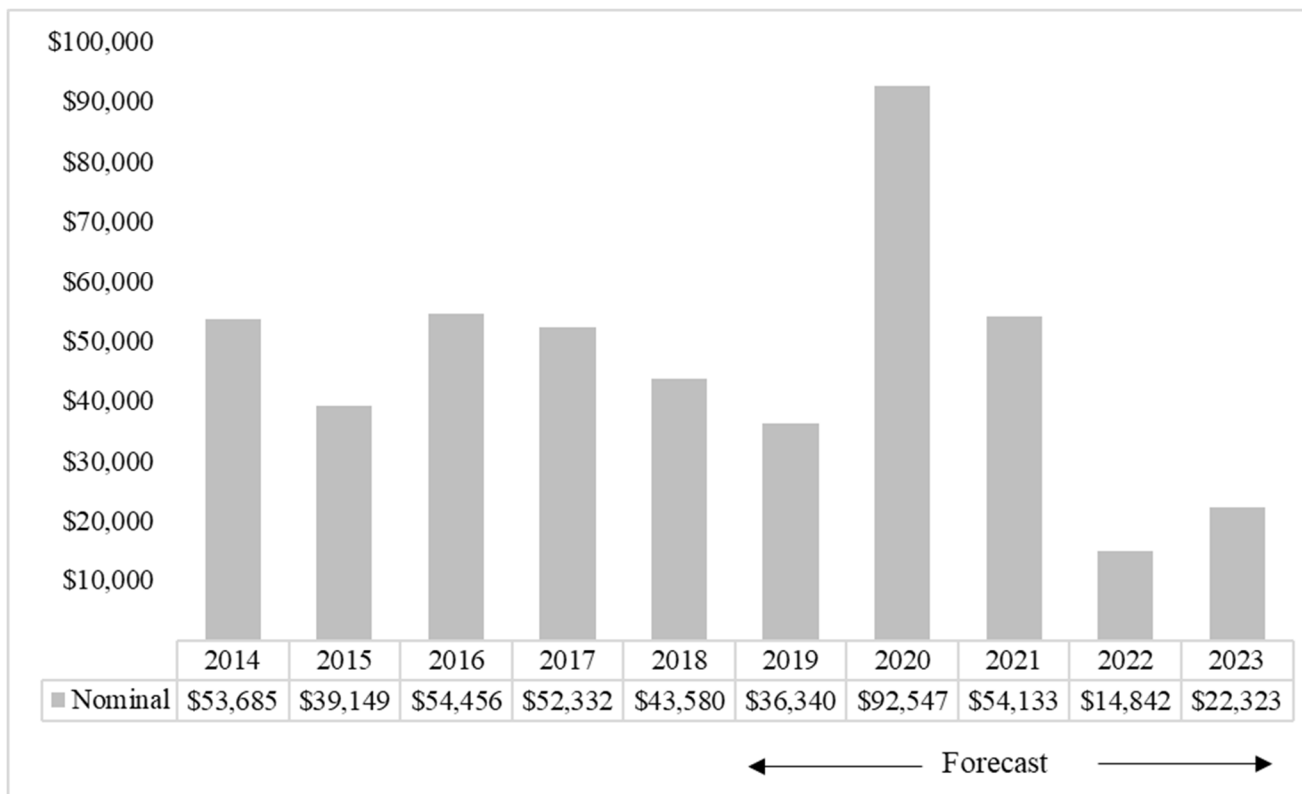
3 The growth ratio is important for Distribution Circuit Upgrades due to the
4 diversity of projects' scope that fall under this category; work performed under this category varies
5 significantly based on the need. It can include installing new switches, upgrading cable or conductor, or
6 installing new conductor to create circuit ties to facilitate load transfers between substations and circuits.
7 It can also include rearrangement of underground facilities to reduce underground cable temperature and
8 installing or replacing equipment to increase the capacity of a distribution circuit. Typically, work for
9 this category is scoped not more than one to two years prior to the distribution need and mitigates the
10 identified need within that timeframe. The diversity of scope and the short turn-around in execution of
11 actual projects means a typical unit cost and unit count methodology isn't optimal. A growth ratio
12 allows for adequate planning given these two factors.

³¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 32 – 33 – Distribution Circuit Upgrades Forecast Methodology.

b) Distribution Substation Plan Circuits

Figure II-8 below shows 2014–2018 recorded and 2019–2023 forecast capital expenditures for the DSP Circuits.

Figure II-8
Distribution Substation Plan Circuits Capital Expenditure Summary
WBS Element CET-ET-LG-CI³²
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description and Need of Program

As part of the DSP Program, new distribution circuits are required to provide new capacity outside the substation fence in areas where multiple distribution circuits in the same geographical region are expected to exceed capacity; to serve new residential or commercial

³² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 34 – 38 – Capital Detail by WBS Element for Distribution Substation Plan Circuits.

1 developments in areas with no existing electrical infrastructure; and to relieve existing circuits projected
2 to exceed capacity in geographically isolated areas with limited usable circuit ties to transfer load.

3 As described in Section II.D.1.a)(1), distribution circuits may also be used
4 to relieve distribution substations expected to exceed capacity by transferring existing customers to a
5 neighboring substation through the circuit. When the existing circuitry does not have adequate capacity,
6 new circuits are needed to accomplish this transfer of customers. As an example, if Substation A is
7 forecast to exceed its substation transformer capacity limit and it is determined that the adjacent
8 Substation B has available substation transformer capacity that can provide loading relief to Substation
9 A through balancing loads between them, SCE evaluates means to transfer load from Substation A to
10 Substation B through the existing distribution circuitry between the two substations. If there is
11 insufficient distribution circuit capacity to accommodate this, SCE evaluates whether construction of a
12 new distribution circuit is economically preferred over other alternatives such as adding substation
13 transformer capacity to Substation A or constructing a new distribution substation. If for example, the
14 distance between Substation A and Substation B is significant and the corresponding new distribution
15 circuit scope is substantial, the cost to construct a new distribution circuit may exceed other alternatives
16 such as substation transformer capacity addition. The option of a new distribution circuit as a solution to
17 offload a neighboring substation is compared to the cost and overall effectiveness of a substation
18 capacity addition project to determine the preferred alternative to meet the long term needs of the area.
19 Figure II-9 represents a graphical depiction of the example.

1 infrastructure addition of a new distribution circuit effectively addressing capacity deficiencies of
2 Substation A. This is performed by utilizing available capacity of Substation B with the net result being
3 the desired reduction of loading at Substation A to within acceptable loading limits while also
4 maintaining the loading at Substation B to within acceptable loading limits. The new distribution circuit
5 also adds operational flexibility to the area by reducing the loading on the highly loaded circuits
6 impacted, thereby increasing their transfer capability, which is especially important during unplanned
7 outages while restoring service.

8 (2) **Basis for Capital Expenditure Forecast**

9 Figure II-8 above shows the historical and forecast costs for all three
10 categories of new distribution circuits resulting from new substation projects, substation capacity
11 increase projects, and projects with unique drivers.

12 Based on the need identified in the DSP process, SCE estimates the cost of
13 new distribution circuits. For circuits that have a need identified approximately two years out, SCE
14 develops detailed plans based on the specific characteristics of the project. The cost estimate for new
15 circuits needed beyond two years are typically estimated using historical costs, since detailed design and
16 cost estimates are not yet completed.³³

17 Costs to construct a new circuit vary depending on several factors such as
18 whether the circuit is overhead or underground, the length of circuit, and geographic location.
19 The voltage of the new circuit is another large contributor in the variation of the cost of a new circuit.
20 New 33kV circuits are typically more expensive than 12kV or 16 kV circuits. This is due to the need for
21 larger equipment and larger facilities to accommodate the higher voltage. The average historic unit costs
22 for 12 kV and 16 kV circuits are \$3.5 million and 33 kV circuits are \$9.8 million.³⁴ For new circuits,
23 SCE's forecast reflects the timing of designing and constructing new distribution circuits. This is
24 becoming increasingly complex due to environmental and permitting requirements of local jurisdictional
25 agencies.

26 To allow sufficient lead time to complete construction of a new circuit,
27 SCE begins the design process one year before the need date for the circuit. Typically, SCE plans to

³³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 39 – 41 – Distribution Substation Plan Circuits Forecast Methodology.

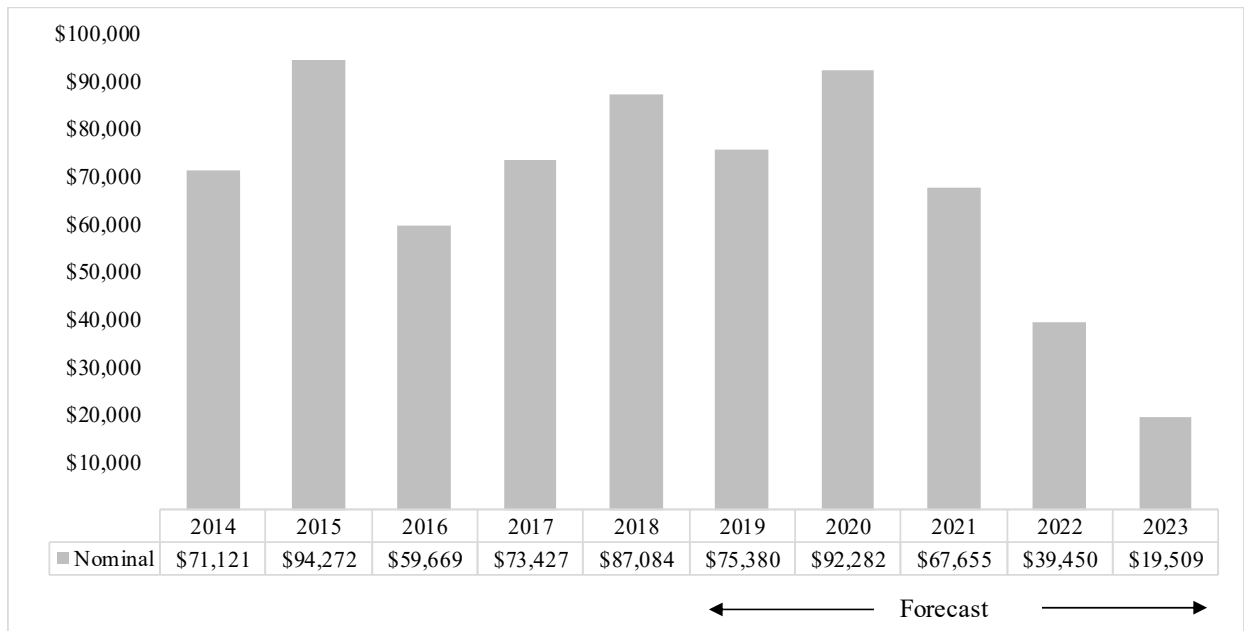
³⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch II – Book A - pp. 39 – 41 – Distribution Substation Plan Circuits Forecast Methodology.

1 spend approximately 10 percent of the cost of a new circuit on early planning and design work one year
 2 prior to the operating date of the circuit, and the remaining approximately 90 percent to complete
 3 construction in the year that the circuit becomes operational.

4 **c) Distribution Substation Plan Substations**

5 Figure II-10 below shows 2014–2018 recorded and 2019–2023 forecast capital
 6 expenditures for the DSP Substations. The figure provides Distribution Substation Plan costs SCE has
 7 already incurred (*i.e.*, expenditures made in 2018 or prior years for projects completed in the 2019-2023
 8 period) and forecast costs for projects planned to be completed through 2023. The capital cost for each
 9 of the projects are presented in the appropriate tables in the Section II.D.1.c)(2), which groups the
 10 projects based on the scope of the work required.

Figure II-10
Distribution Plan Substations Capital Expenditure Summary
WBS Element CET-ET-LG-SU³⁵
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



³⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 42 – 141 – Capital Detail by WBS Element for Distribution Substation Plan Substations.

1 **(1) Program Description**

2 As described in Section II.C.2, SCE identifies required substation projects
3 through the Distribution Substation Planning process when lower cost solutions, such as distribution
4 circuit upgrades or new circuits, do not adequately address an overload. Substation projects include
5 capacity additions or upgrades to facilities at existing substations and within the existing perimeter of
6 the substation property, additions or upgrades that require perimeter expansion of the substation
7 property, and new substations.

8 Distribution substation expansion projects come in two categories:

9 (1) Installation of new, or upgrades to existing, substation equipment within the existing fenced property
10 of a substation; and (2) Installation of new, or upgrades to existing, substation equipment at a substation
11 that requires additional substation property and/or expansion of its existing property to accommodate the
12 capacity increase. Most commonly, the preferred economical solution is to upgrade an existing
13 substation within the existing property prior to proposing to upgrade an existing substation by expanding
14 the property. However, sometimes the scope, costs, or other impacts required to upgrade or expand an
15 existing substation may be prohibitive when compared to the construction of a new substation.
16 These could include such things as power system limitations, limited available space to expand the
17 property, community impacts, and/or environmental impacts. New substation projects are covered in the
18 following section.

(2) Basis for Capital Expenditure Forecast

Table II-3 below provides Distribution Substation Plan costs we have already incurred (*i.e.*, expenditures made in 2018 or prior years for projects completed in the 2019-2023 period) and forecast costs for projects planned to be completed through 2023.

Table II-3
Substation Capacity Projects Capital Expenditure Summary³⁶
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	7796	Sullivan 66/12 kV Substation	Jan-19	2,590	831	-	-	-	-	3,421
2	8079	Sawtelle 66/16 kV Substation	Jan-19	3,887	555	-	-	-	-	4,442
3	7736	Goshen 66/12 kV Substation	Apr-19	5,068	1,814	-	-	-	-	6,882
4	5397	Falcon Ridge 66/12 kV Substation	May-19	63,059	9,019	-	-	-	-	72,078
5	8007	Rosamond 66/12 kV Substation	Jun-19	2,063	2,377	-	-	-	-	4,440
6	8125	Garnet 115/33 kV Substation	Jun-19	389	3,784	-	-	-	-	4,173
7	5194	Presidential 66/16 kV - System Alternative A	Dec-19	9,519	2,586	-	-	-	-	12,105
8	8146	Edwards 115/33 kV Substation	Feb-20	46	2,016	5,010	-	-	-	7,072
9	8143	Signal Hill 66/12 kV Substation	Mar-20	11	38	1,173	1,903	-	-	3,125
10	7516	Safari 33/12 kV Substation	Mar-20	30,429	9,953	5,088	-	-	-	45,470
11	8126	Devers 115/33 kV Substation	Jun-20	69	3,989	8,041	62	-	-	12,162
12	7188	Lee Vining 115/55 kV Hydro Substation	Sep-20	4,584	8,024	13,661	13,098	-	-	39,367
13	5174	San Antonio 66/16 kV Substation	Dec-20	32	1,381	2,043	-	-	-	3,455
14	8101	Lancaster 66/12 kV Substation	Dec-20	79	2,289	4,937	4,080	-	-	11,385
15	8043	Garnet 115/33 kV Substation	Nov-21	520	10,778	37,828	13,497	12,640	-	75,263
16	8102	Del Sur 66/12 kV Substation	Dec-21	164	300	2,900	2,300	-	-	5,664
17	6575	Circle City 66/12 kV Substation	May-23	21,932	1,202	3,479	28,660	19,755	14,595	89,623
18		<i>Subtotal</i>		<i>144,442</i>	<i>60,935</i>	<i>84,160</i>	<i>63,601</i>	<i>32,395</i>	<i>14,595</i>	<i>400,128</i>
19		Projects with CPUC-jurisdictional cost < \$3 M		7,867	13,371	7,973	3,072	4,142	624	37,048
20		Projects with operating date outside of GRC window		154,496	1,074	150	982	2,913	4,290	163,905
21		Total		306,805	75,380	92,282	67,655	39,450	19,509	601,081

SCE has identified 17 substation capacity projects with costs equal to or greater than \$3 million and the total cost for these 17 projects is \$400.1 million. The projects are separated into three categories: substation capacity projects without perimeter expansion, substation capacity projects requiring perimeter expansion, and new substations. Additional projects with less than \$3 million in CPUC-jurisdictional costs are not discussed here, but are included in workpapers.³⁷ The total cost for these projects is \$37.05 million and all of it is CPUC-jurisdictional. Projects with costs in years 2019 - 2023, but have in service dates outside 2019-2023 are not discussed. The total for these

³⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 142 – 327 – Table II-3 Substation Capacity Projects.

³⁷ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 328 – 329 – DSP Substations Projects Less than \$3M CPUC-jurisdictional Costs.

Table II-4
Substation Capacity Projects Without Perimeter Expansion
(Total Company – Nominal \$000)

Line No.	Substation	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
1	Sullivan 66/12	7796	2019	City of Santa Ana	Base load growth Review of substation components resulted in deration of substation capacity	Sullivan 66/12 Substation is projected to reach 105% in 2019 under 1-in-10 weather conditions	Install 1-28 MVA transformer	\$3,421
2	Sawville 66/16	8079	2019	West Los Angeles	Expansion of local metro transportation	Sawville 66/16 Substation is approaching capacity limitations in 2019 under 1-in-10 weather conditions	Remove 2-11.2 MVA transformers Install 2-28 MVA transformers Install 1-16 kV circuit	\$4,442
3	Rosamond 66/12	8007	2019	City of Rosamond	Large industrial growth	Rosamond 66/12 Substation capacity would be unable to serve projected single large customer growth. Based upon analysis of the phase of the customer's load energized in 2018 and uncertainty in the customers future phasing, the overall need for project 8007 was reduced. Project 8007 was already near completion when the forecasted need reduced. Due to the progress already made, the operating date for project 8007 remains in 2019	Remove 1-10 MVA transformer Install 1-14 MVA transformer Rebuild 12 kV switchrack Install 1-12 kV circuit	\$4,440
4	Garnet 115/33	8125	2019	North Palm Springs	New cultivation load in the city of Desert Hot Springs	Garnet 115/33 Substation is projected to reach 104% in 2019 under 1-in-10 weather conditions Person, Greener, and Palmview 33 kV circuits are projected to reach 111.3%, 102.2%, and 100.5% respectively in 2019 under 1-in-10 weather conditions	Install 1-56 MVA transformer Install 2-33kV circuits	\$4,173
5	Devers 115/33	8126	2020	City of Desert Hot Springs	New cultivation load in the city of Desert Hot Springs	Palmview 33 kV circuit is projected to reach 127% in 2020 under 1-in-10 weather conditions Cochella and Pierson 33 kV circuits are projected to reach 249% and 169% respectively in 2021 under 1-in-10 weather conditions	Install 2-56 MVA transformer Install 33 kV switchrack Install 2-33 kV circuits	\$12,162
6	San Antonio 66/16	5174	2020	City of Montclair	Base load growth	San Antonio 66/12 Substation is projected to reach 103% in 2021 under 1-in-10 weather conditions	Remove 2-22.4 MVA transformers Install 2-28 MVA transformers Install 2-12 kV circuits	\$3,455
7	Lancaster 66/12	8101	2020	City of Lancaster	Base load growth New cultivation growth in the city of Lancaster	Lancaster 66/12 Substation is projected to reach 103% in 2019 and 111% in 2021 under 1-in-10 weather conditions	Remove 2-22.4 MVA transformers Install 2-28 MVA transformers Install 1-12 kV circuits	\$11,385
8	Signal Hill 66/12	8143	2020	City of Signal Hill	New cultivation load in the city of Long Beach	Signal Hill 66/12 Substation is projected to reach 110% in 2019 and 112% in 2021 under 1-in-10 weather conditions	Remove 2-14 MVA transformers Install 2-28 MVA transformers	\$3,125
9	Del Sur 66/12	8102	2021	City of Lancaster	New cultivation growth in the city of Lancaster Fleet vehicle electrification	Snowden 12 kV circuit projected to reach 149% in 2021 under 1-in-10 weather conditions	Install 3-12 kV circuits	\$5,664

Table II-5
Substation Capacity Projects Requiring Perimeter Expansion
(Total Company – Nominal \$000)

Line No.	Substation No.	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
1	Goshen 66/12	7736	2019	City of Goshen	Base load growth driven by agricultural and commercial loads	Goshen 66/12 is projected to reach 103% in 2021 under 1-in-10 weather conditions Harrell 12 kV circuit is projected to reach 100.2% in 2021 under 1-in-10 weather conditions Project 7736 was already in construction when the need deferred to 2021. Due to the progress already made the project operating date remains in 2019	Remove 2-14 MVA transformers Remove 1-15.5 MVA transformer Install 2-28 MVA transformers Install 1-12 kV circuit	\$6,882
2	Edwards 115/33	8146	2020	Kern County, East of Rosamond	New cultivation load in California City	Randsburg 115/33 substation projected to reach 257% in 2020 under 1-in-10 weather conditions Heavy 33 kV circuit is projected to reach 315% in 2020 under 1-in-10 weather conditions		\$7,072
3	Garnet 115/33	8043	2021	North Palm Springs	New cultivation load in the city of Desert Hot Springs	Garnet Substation is unable to serve new cultivation load due to the substation configuration	Install 1-56 MVA transformer Relocate 3 - 56 MVA transformers Rebuild 115 kV switchrack Rebuild 33 kV switchrack	\$75,263

Table II-6
New Substation Projects
(Total Company – Nominal \$000)

Line No.	Substation	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
1	Falcon Ridge 66/12	5397	2019	City of Rialto	Large residential developments in the cities of Rialto and Fontana	Randall 66/12 Substation is projected to reach 105% in 2019 under 1-in-10 weather conditions	Construct new 66/12 substation Install 2-28 MVA transformers Install 4-12 kV circuits	\$72,078
2	Safari 33/12	7516	2020	City of Irvine	Large datacenter growth base residential and commercial load growth	Santiago 66/12 Substation is projected to reach 100.1% in 2022 under 1-in-10 weather conditions Euro 12 kV circuit is projected to reach 107% in 2020 and 124% in 2021 under 1-in-10 weather conditions Specialized 12 kV circuit is projected to reach 103% in 2020 under 1-in-10 weather conditions Total 12 kV circuit is projected to reach 106% in 2021 under 1-in-10 weather conditions	Construct new 33/12 substation Install 2-28 MVA transformers Install 3-12 kV circuits Construct new 66/33 substation Install 2-56 MVA transformers Install 2-33 kV circuits	\$45,470

1 (c) **Substation Projects With Unique Drivers**

2 The dedicated descriptions below explain the unique nature of
3 three projects that do not fit in the three categories described above. These projects involve a system
4 alternative for a new substation and rebuilding a hydro substation facility.

5 (i) **Presidential 66/16 kV Substation – System Alternative**
6 **A (Project #5194)**

7 Presidential 66/16 kV Substation was a new proposed
8 substation planned near the border of Thousand Oaks and Simi Valley. The CPUC issued an amendment
9 to the final EIR on November 26, 2013 and the final Decision³⁹ selected “System Alternative A” as the
10 preferred project, with the Presidential 66/16 kV substation project as the alternative project. The project
11 scope includes work at Royal 66/16 kV Substation in the city of Simi Valley and Potrero 66/16 kV
12 Substation in the city of Thousand Oaks. Royal 66/16 kV and Potrero 66/16 kV are projected to
13 approach capacity limits due to continuing residential load growth in Simi Valley and both residential
14 and commercial load growth in Thousand Oaks. The scope of work at Royal 66/16 kV Substation was to
15 replace a 22.4 MVA transformer bank with a 28 MVA transformer bank with an operating date of June
16 2016 and construct one new 16 kV distribution circuit with an operating date of June 2017. The scope of
17 work at Potrero 66/16 kV Substation was to construct a new 16 kV distribution circuit with an operating
18 date of June 2018 and replace limiting substation components to increase substation capacity with an
19 operating date of June 2019. The total project cost including work at both substations is \$12.1 million.

20 SCE has identified one alternative for this project.

21 The alternative is to construct the new Presidential 66/16 kV Substation consisting of two 28 MVA,
22 66/12 kV transformers and four 16 kV distribution circuits. The preferred project “System Alternative
23 A,” was selected as part of D.14-03-006⁴⁰ and is the least-cost solution.

24 (ii) **Lee Vining 115/55 kV Hydro Substation (Project #7188)**

25 Lee Vining 115/55 kV Substation is in the southern portion
26 of Lee Vining in Mono County, serves customers in the town of Lee Vining and provides
27 interconnection to multiple hydro generators in the area. Lee Vining 115/55 kV Substation was built in
28 the early 1900’s with a bus configuration that requires an outage for all customers served by the

³⁹ D.14-03-006.

⁴⁰ *Id.*

1 substation when any substation equipment requires servicing. The substation is also located
2 approximately a quarter mile from the Mono Lake Fault line and has antiquated equipment that is
3 vulnerable to significant earthquakes. The scope of the project includes a complete rebuild of the
4 substation to current reliability and seismic standards. This includes rebuilding the 115 kV and 55 kV
5 switchracks, replacing the 2.4 kV switchrack with a 12 kV switchrack, installing two 7 MVA 115/55 kV
6 transformers, and installing two 14 MVA 55/12 kV transformers. Upon completion of rebuilding Lee
7 Vining Substation, the Cain Ranch 2.4/12 kV substation will be decommissioned and the existing 2.4 kV
8 circuit currently served from Lee Vining Substation will require a new 12/2.4 kV pole top transformer.
9 This will allow SCE to continue serving customers from the same 2.4 kV distribution circuit.
10 The operating date is September 2020 with a total project cost of \$39.4 million.

11 SCE has identified one alternative for this project.

12 The alternative is to eliminate the 55 kV facilities at Lee Vining 115/55 kV substation, which would
13 require upgrades to subtransmission lines and neighboring Lundy 55/16 kV substation. Under this
14 alternative, the scope of work at Lee Vining 115/55 kV substation would include converting the
15 substation from 115/55/2.4 kV to a 115/12 kV substation, rebuilding the 115 kV switchrack, installing
16 two 7 MVA 115/12 kV transformers, replacing the low voltage switchrack from 2.4 kV to 12 kV, and
17 reconfiguring distribution circuitry. The scope of work at Lundy 55/16 kV substation would include
18 replacing the existing 55 kV switchrack with a 115 kV switchrack, install two 14 MVA 115/16 kV
19 transformers, and install one 5 MVA 115/2.4 kV transformer to interconnect existing hydroelectric
20 generation. The subtransmission line work includes replacing approximately 14.8 miles of conductor
21 and poles converting both Lee Vining-Lundy No.1 and Lee Vining-Lundy No.2 from 55 kV to 115 kV
22 and tie in a new subtransmission line to feed temporary 115/55 kV transformation while the Lee Vining
23 115/55 kV substation rebuild construction is completed. The preferred project was selected because it is
24 the most cost-effective solution.

25 **(iii) Circle City 66/12 kV Substation (Project #6575)**

26 The Circle City 66/12 kV Substation Project was originally
27 proposed as a single project that combined two primary scope elements: 1) a new 66/12 kV distribution
28 substation (Circle City Substation), and 2) a new 66 kV subtransmission line (Mira Loma-Jefferson 66
29 kV Line). The Circle City 66/12 kV Substation portion of the project was a new proposed substation
30 planned in the City of Corona. Residential and commercial load growth was projected to exceed the
31 capacity of the existing facilities in the area: Corona 66/12 kV Substation, Chase 66/12 kV Substation,

1 Jefferson 66/12 kV Substation. The Mira Loma-Jefferson 66 kV Line portion of the project was a
2 proposed new 10.9 mile 66 kV subtransmission line connecting Mira Loma Substation and Jefferson
3 Substation addressing projected overload conditions on the existing 66 kV lines serving the area.

4 In recent planning cycles, the anticipated load growth in the
5 area has not materialized at the rate previously expected and may be attributed to a reduction in the
6 forecast due to increased DER adoption and new load growth being served by a local electrical
7 municipality which was previously anticipated to be served by SCE.

8 As a result of the reduction of the forecast, current load
9 projections do not demonstrate a capacity need for the Circle City Substation portion of the project.
10 Additionally, while the need for the Mira Loma-Jefferson 66 kV Line portion of the project persists.

11 As a result, the scope of Project 6575 has been reduced by
12 eliminating the Circle City Substation portion of the project while retaining the Mira Loma-Jefferson 66
13 kV Line portion. The revised scope now includes only installing a 66 kV line position and circuit
14 breaker at Mira Loma 220/66 kV Substation, installing approximately 10.9 miles of new 66 kV circuitry
15 (10.5 miles overhead and 0.4 miles underground) to connect with the existing Jefferson segment of the
16 existing Mira Loma-Corona-Jefferson 66 kV Subtransmission line. The total cost for Project 6575 is
17 \$89.6 million.

18 **(d) Licensing Status of New Substations and Substations**
19 **Requiring Perimeter Expansions**

20 SCE must comply with the licensing provisions of General Order
21 131-D (G.O. 131-D) before constructing electric facilities operating at voltages greater than 50 kV.⁴¹
22 Table II-7 below contains the licensing and exemption information for each of DSP Substation projects.
23 Besides identifying the projects for which Certificate of Public Convenience and Necessity (CPCN)⁴² or
24 Permit to Construction (PTC)⁴³ applications have already been filed under G.O. 131-D, a review of the
25 project in Table II-7. This review aimed to determine 1) the need for a CPCN or PTC application to be
26 filed under G.O. 131-D, 2) whether a project could qualify for an exemption under G.O. 131-D, or 3)

⁴¹ D. 94-06-014, D.95-08-038 Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California.

⁴² General Order 131-D, Section A.

⁴³ General Order 131-D, Section B.

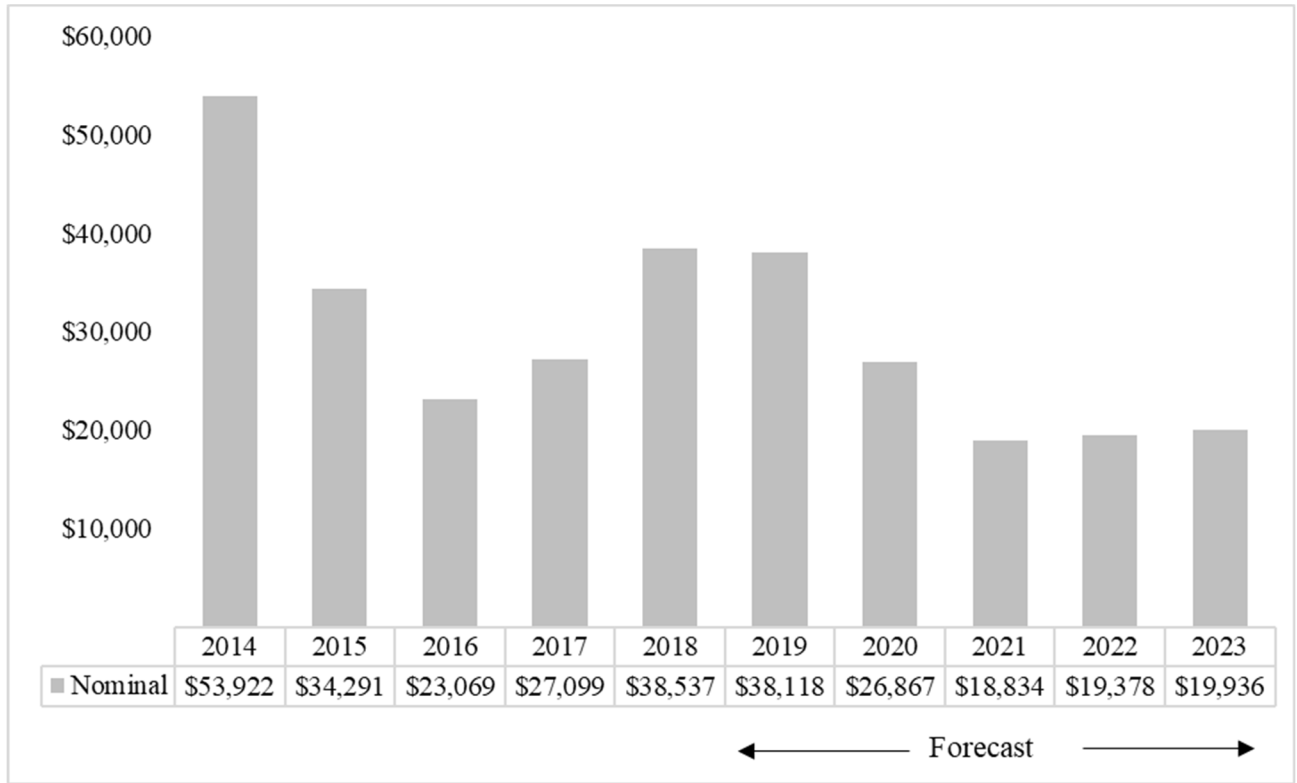
Table II-7
Construction Licensing Under G.O 131-D

Line No.	Project No.	Project Name	Operating Date	Preliminary Licensing Determination
1	7796	Sullivan 66/12 kV Substation	Jan-19	Substation Modification
2	8079	Sawtelle 66/16 kV Substation	Jan-19	Substation Modification
3	7736	Goshen 66/12 kV Substation	Apr-19	Substation Modification
4	5397	Falcon Ridge 66/12 kV Substation	May-19	PTC Received 2/10/2014
5	8007	Rosamond 66/12 kV Substation	Jun-19	Substation Modification
6	8125	Garnet 115/33 kV Substation	Jun-19	Substation Modification
7	5194	Presidential 66/16 kV - System Alternative A	Dec-19	PTC Received 3/13/2014
8	8146	Edwards 115/33 kV Substation	Feb-20	In Review Expected Substation Modification
9	8143	Signal Hill 66/12 kV Substation	Mar-20	Substation Modification
10	7516	Safari 33/12 kV Substation	Mar-20	Substation Modification
11	8126	Devers 115/33 kV Substation	Jun-20	Substation Modification
12	7188	Lee Vining 115/55 kV Hydro Substation	Sep-20	Substation Modification
13	5174	San Antonio 66/16 kV Substation	Dec-20	Substation Modification
14	8101	Lancaster 66/12 kV Substation	Dec-20	Substation Modification
15	8043	Garnet 115/33 kV Substation	Nov-21	Substation Modification/Exemption B
16	8102	Del Sur 66/12 kV Substation	Dec-21	Substation Modification
17	6575	Circle City 66/12 kV Substation	May-23	Final EIR Published 12/5/2018

d) 4 kV Cutovers – Load Growth Driven

Figure II-11 below shows 2014–2018 recorded and 2019–2023 forecast capital expenditures for 4kV Cutovers – Load Growth Driven.

Figure II-11
4kV Cutovers – Load Growth Driven Capital Expenditure Summary
WBS Element CET-ET-LG-4C⁴⁷
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description and Need for Activity

The 4 kV Cutovers – Load Growth Driven program addresses overloads on 4 kV circuits and substations due to load growth in areas that these circuits and substations serve. Most of SCE’s distribution circuits operate at voltages of 12 kV, 16 kV, or 33 kV. However, about 19 percent of distribution circuits and about 27 percent of distribution substations operate at voltages of 2.4 kV, 4.16 kV, and 4.8 kV,⁴⁸ which comprise 4 kV Cutovers – Load Growth Driven program. A cutover is defined as change of primary service voltage from lower to higher voltage, including change out of service transformers, conductor insulation, and other relevant equipment to facilitate

⁴⁷ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 332 – 333 – Capital Detail by WBS Element for 4 kV Cutovers – Load Growth Driven.

⁴⁸ Herein collectively referred to as 4 kV systems.

1 cutover. Many of the 4 kV circuits and substations make up some of the oldest parts of our system,
2 much of which was designed and installed between 1940 and 1960. Over time, the age and obsolescence
3 of this system poses challenges with providing service to additional load growth in those areas.

4 When new load growth projects or forecasted load growth cannot be
5 served from existing infrastructure, SCE typically proposes equipment upgrades such as an increase in
6 substation transformer capacity or construction of a new circuit. The 4 kV system has limitations, such
7 as equipment obsolescence, space constraints, limited operational flexibility, and voltage issues, which
8 are described more in-depth below and in 4 kV Substation Elimination Program in SCE-02 V.01
9 Distribution Grid Part 1 – Distribution Infrastructure Replacement. For 4 kV circuits and substations
10 experiencing overloads, SCE’s approach is to partially or completely cutover circuits, enough to reduce
11 the loading below the established planned loading limits.

12 The typical 4 kV circuit can serve only approximately 2.3 MW of load
13 when compared to a standard 12 kV circuit designed and capable of serving over 10 MW, based on
14 thermal and protection limitations. The average ability of a 4 kV circuit to serve customers is less than
15 half that of higher voltages; averaging roughly 660 customers per 4 kV circuit in compared to almost
16 1,400 customers for 12 kV and 16 kV. While the load density on 4 kV circuits is lower, these limitations
17 prevent circuits from being expanded to accommodate any substantial increases in customer demand.
18 Because SCE cannot prevent customers from adding additional load in the areas that are served by 4 kV
19 circuits, SCE continues to experience overloads which continues to drive a need for the 4 kV Cutovers -
20 Load Growth Driven program.

21 Underground cable, overhead conductor, substation voltage regulators,
22 and substation transformers limit 4 kV circuit and substation capacity. Due to the lower demand of
23 customers at the time when new 4 kV infrastructure was designed, both the cable itself and the ducts
24 protecting the cable are much smaller than today’s SCE standards require. PILC (Paper-Insulated Lead-
25 Covered) cable, which is environmentally hazardous due to lead but prevalent across 4 kV distribution
26 circuits, was designed to have a minimal diameter and a relatively small conduit, generally no more than
27 3” in diameter. When PILC cable is projected to be overloaded, the 3” conduit limits the size of
28 replacement cable, which could limit circuit capacity or require higher costs to maintain similar
29 capacity. Cutover to 12 and 16 kV voltage, which utilizes SCE’s standard 5” conduit for mainline cable,
30 can accommodate cables with larger current carrying capacity. Similarly, smaller gauge of wire was
31 used for 4 kV overhead conductor construction. Approximately 65% of overhead conductors on 4 kV

1 systems are wires smaller than 1/0 Aluminum Conductor Steel Reinforced (ACSR). Higher demand
2 from our customers today leads to thermal overloads of these smaller conductors and the need to
3 increase the capacity.

4 Many of SCE's 4 kV substations do not meet current design standards that
5 require specific substation dimensions, configurations, and equipment. The addition of new load growth
6 to 4 kV systems will eventually result in the need to expand and upgrade substation equipment, in
7 addition to circuit upgrades. The need to upgrade or add a piece of equipment like a new 4 kV substation
8 transformer often requires more significant work to be done and potentially the need to rebuild
9 substations to current design standards.

10 With additional new load, other 4 kV substation equipment such as
11 voltage regulators can become overloaded. The result of these overloads is reduced voltage regulation
12 capability, excess strain on the equipment, and reduced loading capacity on the circuit.

13 The limitations of the 4 kV system described above do not allow SCE to
14 safely and cost-effectively serve additional load growth and thus require cutover to higher voltage before
15 new load growth can be added to the area.

16 Additionally, some 4 kV systems are islanded because there are no
17 physical connection points to other 4 kV circuits/substations. During a contingency (planned or
18 unplanned outage), it is not feasible to restore power to customers through the transfer of the 4 kV load
19 to an adjacent circuit. Without this transfer capability, both planned and emergent maintenance can
20 negatively impact reliability. To maintain safe and reliable service to the customers that are currently
21 served from islanded 4 kV systems, SCE plans to cutover sections of circuit or full circuits that do not
22 have adequate operational flexibility.

23 (2) Basis for Capital Expenditure Forecast

24 As mentioned in other Load Growth capital expenditures, the needed
25 capital expenditures for the 4 kV Cutovers - Load Growth Driven program is higher than what SCE
26 estimates it will execute due to Grid Resiliency priorities and resource constraints. The forecast in
27 Figure II-11 is based on the two categories of 4 kV load growth needs described above. SCE identified
28 4 kV circuits that would be overloaded over the next ten years due to load growth exceeding equipment
29 limitations and the corresponding number of 4 kV transformers on those circuits that would be required
30 to be cutover to a higher voltage. The forecast is split between (1) 2019-2020 based on detailed scope
31 and (2) 2021-2023 unit counts based on remaining ten-year need levelized over 2021-2028. Each year's

1 transformer count is multiplied by a transformer unit cost calculated based on historical average of
2 cutovers divided by the total number of 4 kV transformers replaced over the years 2014-2018.⁴⁹
3 The second category of 4 kV circuits that need to be cutover is driven by islanded 4 kV circuits.
4 The contingency-driven 4 kV cutovers in the forecast is only included as part of the 2019 detailed scope
5 due to resource constraints.

6 **2. DER-Driven Grid Reinforcement**

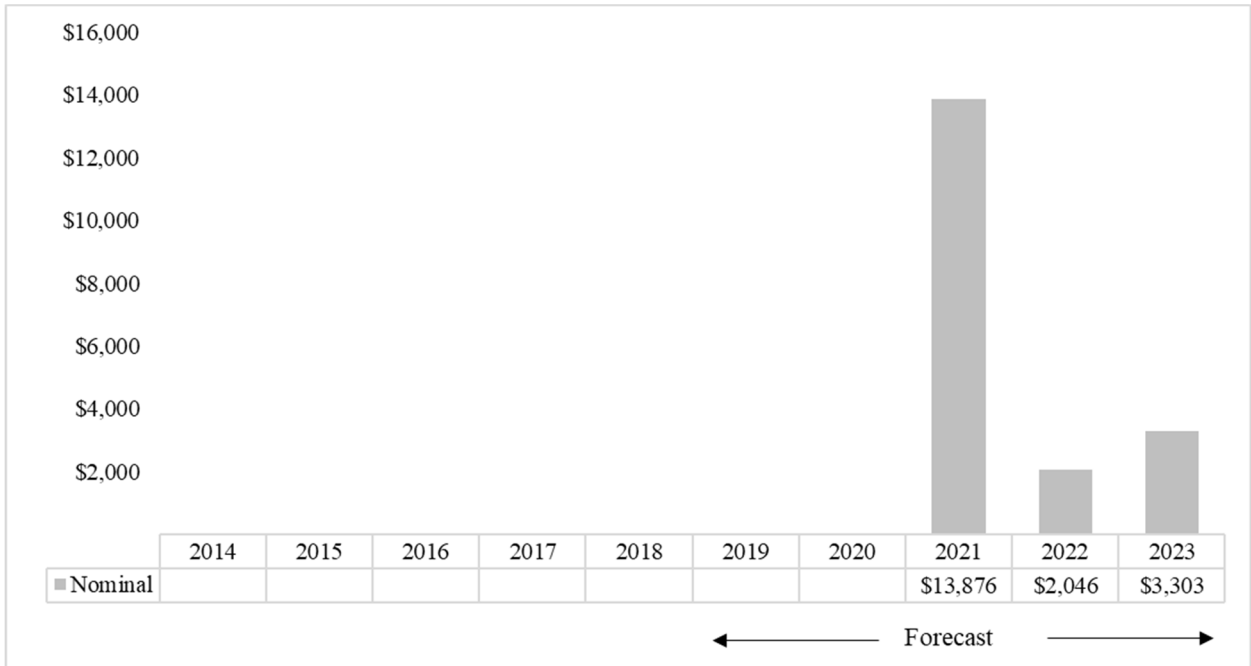
7 DER-Driven Grid Reinforcement capital expenditures upgrade the distribution system to
8 enable the integration of DERs. The upgrades shown below are required to mitigate criteria violations
9 that can compromise the safety and reliability of the distribution grid due to distribution assets
10 exceeding equipment limitations or reducing the operational flexibility of the grid. These DER-Driven
11 Grid Reinforcements include circuit upgrades, 4 kV cutovers, new distribution circuits, circuit breaker
12 upgrades, and substation transformer upgrades. SCE uses distribution planning criteria to determine
13 potential DER-driven violations. SCE has identified five categories of mitigations to address these
14 violations that are discussed in more detail below.

15 **a) DER-driven Distribution Circuit Upgrades**

16 Figure II-12 below shows the forecast capital expenditures for the DER-driven
17 Distribution Circuit Upgrades. The forecast expenditures start in 2021.

⁴⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 334 – 336 – 4 kV Load Growth Cutovers Forecast Methodology.

Figure II-12
DER-driven Distribution Circuit Upgrades Capital Expenditure Summary
WBS Element CET-PD-GM-LR⁵⁰
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description

DER-driven Distribution Circuit Upgrades covers forecast expenditures for work outside of the substation required to relieve heavily loaded distribution circuits forecast to exceed distribution planning criteria limits due to increased DER growth. Work in this category enables distribution circuits to carry more electric current to mitigate situations where equipment is forecast to exceed capacity limits. SCE performs a system-wide analysis to determine needed upgrades based on the increased DER growth using the CEC IEPR forecast described in Section C.1.c). The work includes upgrading cable or conductors, installing new voltage regulators, and installing new automatic reclosers. These projects were triggered due to conductor ratings being exceeded, system voltage outside of our criteria, and inadequate protection on the distribution system. These upgrades are necessary because as more DERs integrate into the system, they will cause smaller conductors to become overloaded, voltage

⁵⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 1 - 2 – Capital Detail by WBS Element for DER-driven Distribution Circuit Upgrades.

1 to go outside of acceptable criteria, and/or protection schemes to become inadequate due to short circuit
2 current contributions from DERs.⁵¹ And as discussed in Section C.1.c), as DER growth increases, these
3 issues can exist outside of traditional peak load conditions.

4 (2) **Basis for Capital Expenditure Forecast**

5 SCE bases its DER-driven Distribution Circuit Upgrades forecast on
6 reliability criteria violations projected from DER growth as explained in Section C.1.⁵² As with other
7 Load Growth capital expenditures, the forecasts are impacted by anticipated resource constraints due to
8 Grid Resiliency efforts. Since the variety of upgrades proposed is small (in comparison to the diversity
9 of those proposed for traditional load growth in Section 1.a)), the DER-driven Distribution Circuit
10 Upgrades forecast is based on unit costs developed for each upgrade type from historical averages over
11 2014-2018. The actual years of data varies whether projects of that type were completed in those years
12 historically.

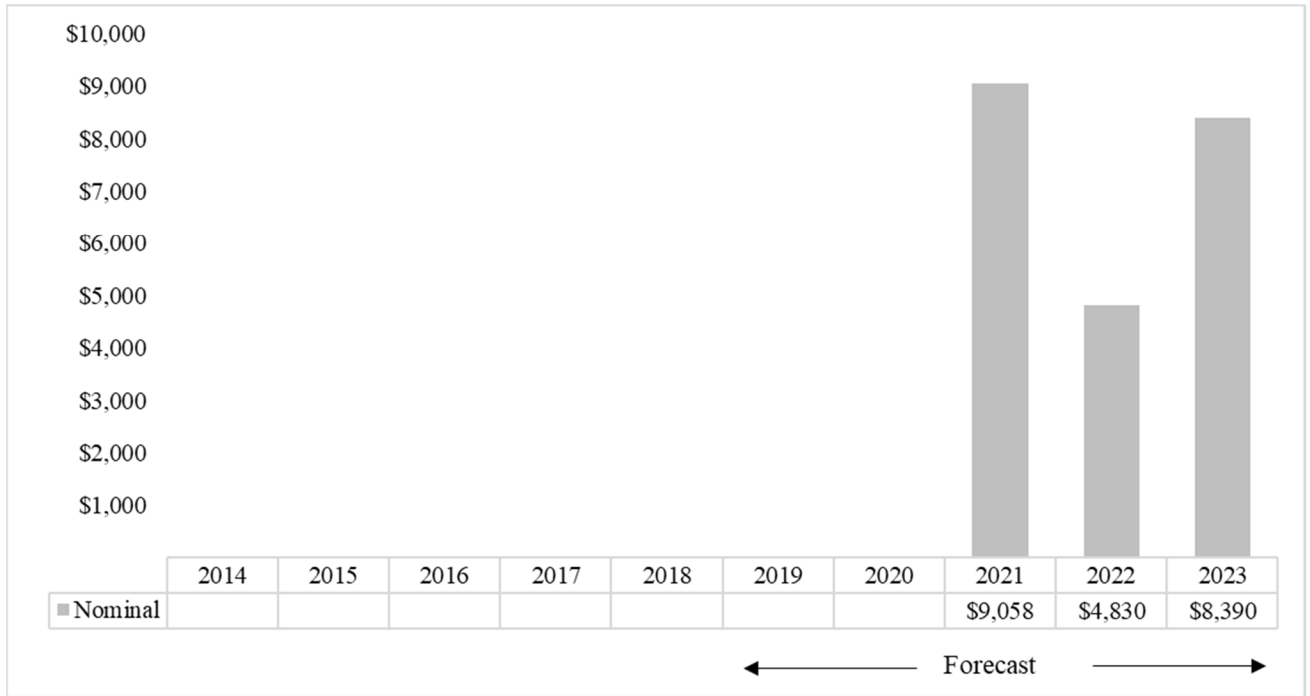
13 b) **DER-driven 4 kV Cutovers**

14 Figure II-13 below shows the 2019–2023 forecast capital expenditures for the
15 DER-driven 4 kV Cutovers. The forecast expenditures start in 2021.

⁵¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

⁵² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 3 - 5 – DER-driven Distribution Circuit Upgrades Forecast Methodology. SCE performed simulations for DER-driven line section related needs for 2019 – 2023. The results of these simulations were used to identify line segment specific needs for the 2019 - 2021 period, and SCE has higher confidence those needs will persist in the specific locations identified by the simulation. However, simulation results for 2022 – 2023 were used to inform the general level of funding that will be required to serve the expected needs in that period, as the locations of these projects are subject to a higher degree of change over time. While locations of projects may change, the need for this work is expected to remain at the levels forecast for 2022 – 2023.

Figure II-13
DER-driven 4 kV Cutovers Capital Expenditure Summary
WBS Element CET-PD-GM-4C⁵³
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description

SCE distribution system is mainly composed of four voltage classes: 4 kV, 12 kV, 16 kV, and 33 kV. SCE analyzed 4 kV circuits to determine impacts from forecasted DER penetration.⁵⁴ The criteria are the same as used for load growth-driven 4 kV cutovers. This includes exceedance of the thermal rating of conductors and violation of voltage criteria. DERs on 4 kV circuits can often increase the amps flowing on the circuit. During minimum loading conditions, this can cause the flow of the amps to go back into the substation and can lead to thermal and voltage violations. The results of this analysis identified circuits that need to be cutover to a higher voltage feeder.⁵⁵

⁵³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 6 - 7 – Capital Detail by WBS Element for DER-driven 4 kV Cutovers.

⁵⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 – 29 – High Distributed Energy Resources Planning Assumptions.

⁵⁵ The need to cutover to a higher voltage is explained in the 4 kV Cutovers – Load Growth section.

1 To avoid overlapping projects with the other 4 kV circuit cutovers, the study compared the circuits to be
2 eliminated to the distribution planning process, to ensure there was no double-counting on the projects,
3 and only circuits not already identified in other 4 kV elimination programs were selected for a cutover
4 under this program.

5 **(2) Basis for Capital Expenditure Forecast**

6 SCE bases its DER-driven 4 kV Cutovers forecast on reliability criteria
7 violations projected from DER growth as explained in Section C.1. As with other Load Growth capital
8 expenditures, the forecasts are impacted by anticipated resource constraints due to Grid Resiliency
9 efforts. Although the need for cutovers and the criteria violations are the same as the 4 kV cutovers
10 driven by Load Growth, the DER-driven cutover work is very similar to the transformer replacement
11 costs from 4 kV Substation Elimination Program. To develop the forecast,⁵⁶ DER-driven 4 kV Cutovers
12 used the unit cost⁵⁷ from 4 kV Substation Elimination Program.

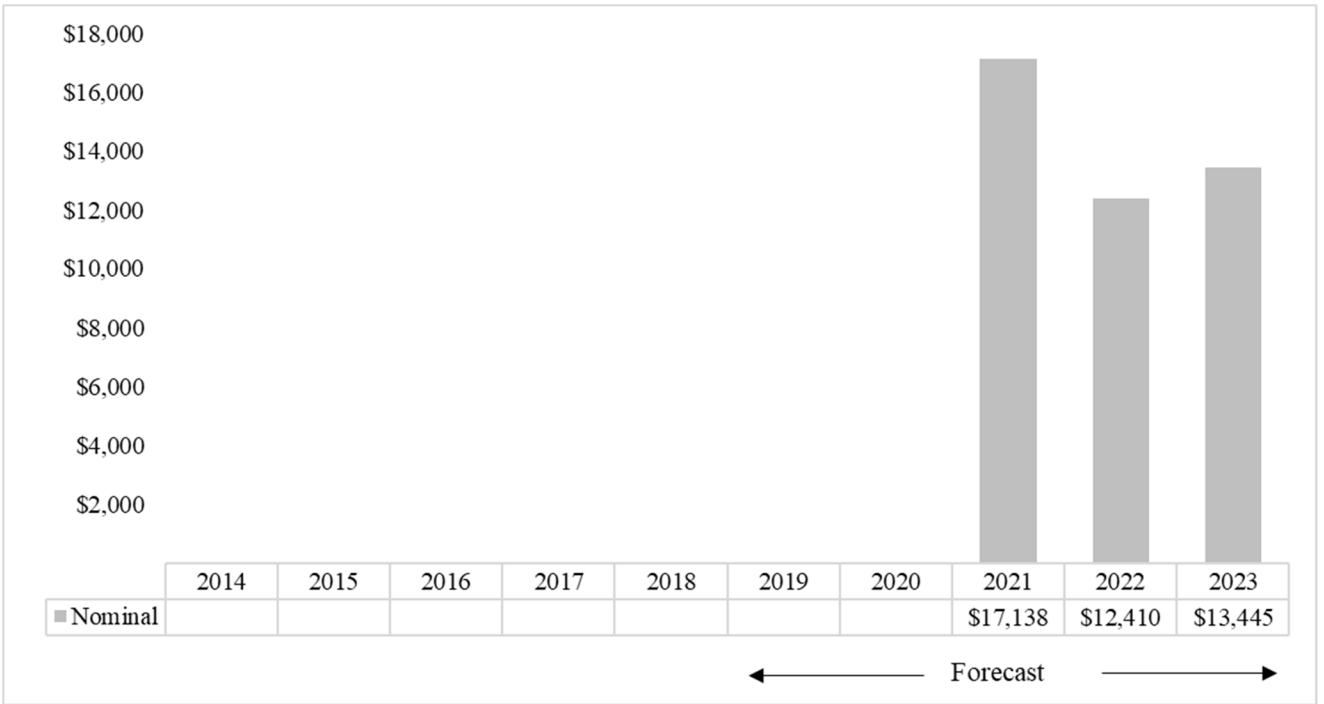
13 **c) DER-driven New Circuits**

14 Figure II-14 below shows the 2019–2023 forecast capital expenditures for the
15 DER-driven New Circuits. The forecast expenditures start in 2021.

⁵⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 8 - 10 – DER-driven 4 kV Cutovers Forecast Methodology.

⁵⁷ Refer to WP SCE-02 Vol. 01, Pt. 1 – pp. 97 - 98 – Cost of Cutting Over a 4 kV Circuit.

Figure II-14
DER-driven New Circuits Capital Expenditure Summary
WBS Element CET-PD-GM-CI⁵⁸
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description

High DER penetration also drives the need for new circuits.

Unlike traditional load growth, the impacts of DERs (due to the proportion of photovoltaic technology)⁵⁹ tends to be highest during periods of minimum daytime loading. Accordingly, increased DER growth and penetration can cause power to reverse back to the substation. This amount of reverse power flow can cause equipment to exceed its planned loading limit, which leads to that equipment exceeding its thermal rating and voltage moving outside of criteria. This can lead to compromising the operational flexibility required to maintain a dynamic distribution system. Accordingly, new circuit projects are

⁵⁸ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 11 - 12 – Capital Detail by WBS Element for DER-driven New Circuits.

⁵⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 14 - 29 – High Distributed Energy Resources Planning Assumptions.

1 required to minimize reverse power flow through the distribution circuits, ensure that planned loading
2 limit is not exceeded, and to ensure adequate flexibility is maintained in the distribution system.

3 **(2) Basis for Capital Expenditure Forecast**

4 SCE bases its DER-driven New Circuit forecast on reliability criteria
5 violations projected from DER growth as explained in Section C.1. The DER-driven New Circuit
6 forecast⁶⁰ uses the unit costs developed for Distribution Substation Plan Circuits in Section 1.b)(2) based
7 on final costs for DSP circuits completed between 2016 and 2018.⁶¹

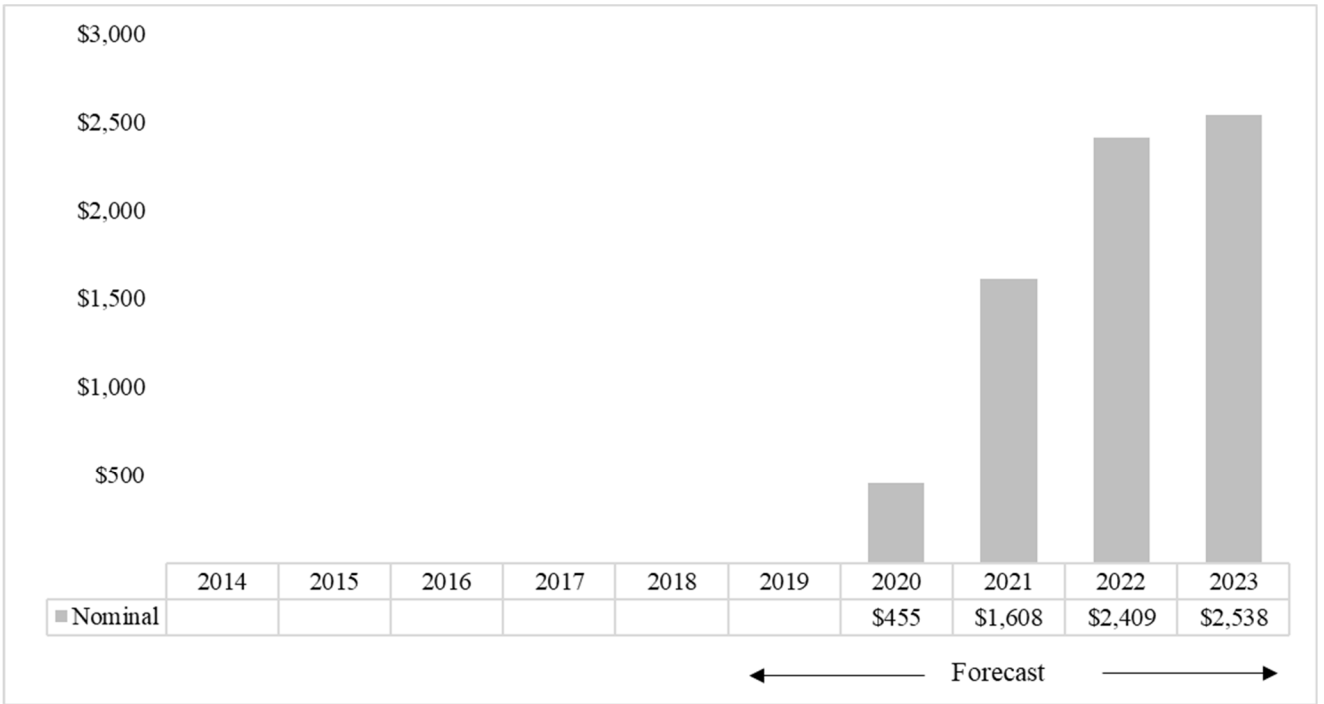
8 **d) DER-driven Circuit Breaker Upgrades**

9 Figure II-15 below shows the 2019–2023 forecast capital expenditures for the
10 DER-driven Circuit Breaker Upgrades. The forecast expenditures start in 2020.

⁶⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 13 - 15 – DER-driven New Circuits Forecast Methodology.

⁶¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book A - pp. 39 - 41 – Distribution Substation Plan Circuits Forecast Methodology.

Figure II-15
DER-driven Circuit Breaker Upgrades Capital Expenditure Summary
WBS Element CET-PD-GM-CB⁶²
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description

DER-driven Circuit Breaker Upgrades identify circuit breakers for upgrades as they approach or exceed their fault current ratings due to DERs adding short circuit current during a fault. Under this analysis, SCE identifies substations where available fault current, or short-circuit duty, exceeds safe equipment ratings essential to the provision of safe and reliable service. SCE’s electrical distribution system is designed to safely detect and isolate faults. When a fault occurs, dangerous levels of current flow from all electrical sources (generators) to the location of the fault. Prolonged fault current will cause major damage to distribution equipment, can cause catastrophic failure, and can seriously jeopardize public and employee safety. Due to the magnitude of fault current, a fault condition must be isolated quickly to restore safe operating conditions of the power system.

⁶² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 16 - 17 – Capital Detail by WBS Element for DER-driven Circuit Breaker Upgrades.

1 Substation circuit breakers are the most common devices used to isolate faults and are relied upon to
2 interrupt the highest fault currents experienced on the distribution system. Substation circuit breakers
3 incapable of interrupting expected fault currents are likely to fail when those faults occur.

4 The IEPR forecasts increased DER penetration on the distribution system.
5 When that happens the total amount of short circuit duty on the system increases as DERs contribute to
6 and increase the amount of short circuit duty on the system. SCE performed a system-wide analysis to
7 determine the substations which are anticipated to experience increased short circuit current due to the
8 increase in fault contribution from DERs. Where the short circuit duty levels exceed the fault current
9 rating of the circuit breakers, SCE plans to upgrade the circuit breaker with a higher fault current rating,
10 capable of safely interrupting the fault on the system.

11 **(2) Basis for Capital Expenditure Forecast**

12 SCE identified circuit breaker upgrades over the five-year forecast
13 period.⁶³ The identified projects were checked against those identified in SERP and the Substation
14 Infrastructure Replacement Circuit Breaker program, no duplicates are included. Unit Cost used for this
15 program is the same unit costs that the Substation Equipment Replacement Program are using.⁶⁴
16 Since both programs identify specific circuit breakers to be replaced and the unit costs are developed per
17 voltage classes, the unit costs from SERP are most appropriate for this new program.

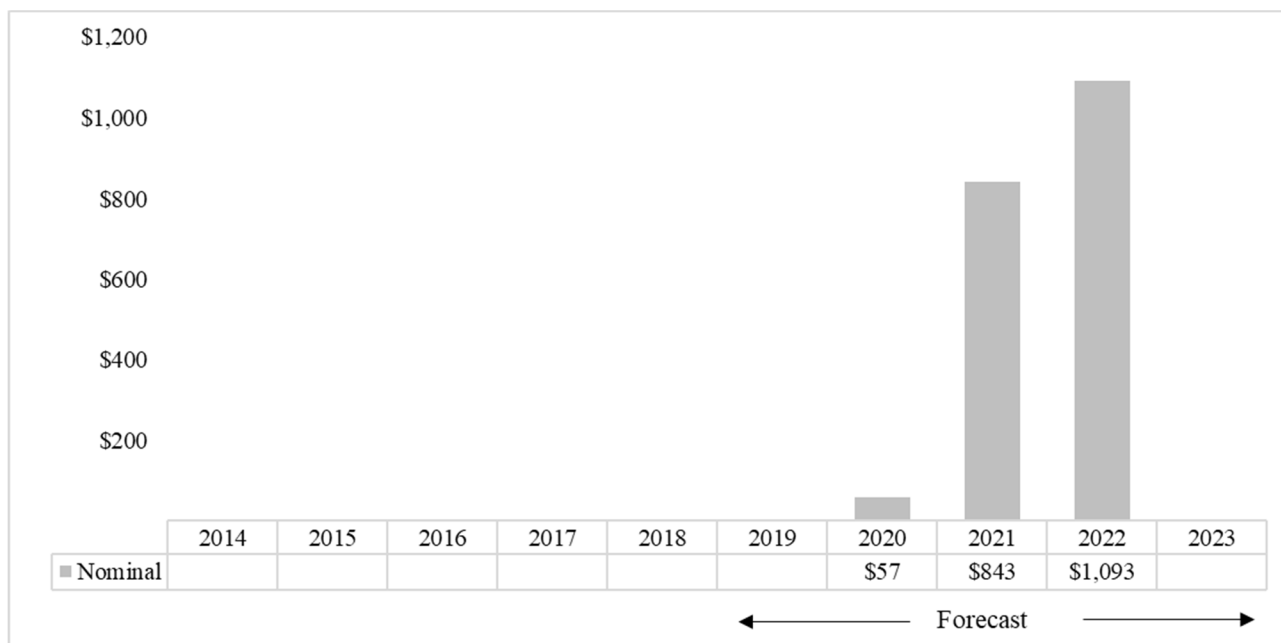
18 **e) DER-driven Substation Transformer Upgrades**

19 Figure II-16 below shows 2019–2023 forecast capital expenditures for the DER-
20 driven Substation Transformer Upgrades. The forecast expenditures start in 2020.

⁶³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II - Book B - pp. 18 - 19 – DER-driven Circuit Breaker Upgrade Forecast Methodology.

⁶⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 20 - 22 – Substation Equipment Replacement Program Forecast Methodology.

Figure II-16
DER-driven Transformer Upgrades Capital Expenditure Summary
WBS Element CET-PD-GM-TB⁶⁵
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description

SCE identifies required substation projects through the Distribution Substation Planning process which includes capacity additions or upgrades to facilities at existing substations and within the existing perimeter of the substation property, additions or upgrades that require perimeter expansion of the substation property, and new substations. The project under the DER-driven Substation Transformer Upgrades increases the substation capacity at existing substations. The driver of this project is the DER penetration at a distribution substation level. Just as the increase in number of DERs on the system can cause reverse power flow at the circuit level, the same effect can be had at the distribution substation level. When all the circuits connected to a substation are experiencing reverse power (due to DER growth peaking during non-peak hours), this reverse power aggregates at the substation level. Further, it flows back through the distribution substations and into the higher voltage

⁶⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 23 - 24 – Capital Detail by WBS Element for DER-driven Substation Transformer Upgrades.

1 systems. Just as with traditional load growth-driven programs, when the amount of power flowing
2 through our equipment exceeds planned loading limits, SCE designs a project to help mitigate the
3 problem. The project under this program follow the same criteria as load growth-driven projects;
4 however, these DER-driven projects address the amount of power flowing through the distribution
5 substation that is being pushed back from the total aggregate reverse power from the distribution
6 circuits.

7 **(2) Basis for Capital Expenditure Forecast**

8 Only one transformer bank was identified as exceeding its capacity rating
9 due to the DER growth in the five year forecast period. A unit cost⁶⁶ was used based on historical work
10 order averages completed between 2015-2017 in the same voltage class. The forecast in Figure II-16
11 shows the forecasts and expected expenditures for the work to upgrade the transformer bank.

⁶⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 25 - 26 – DER-driven Transformer Upgrades Forecast Methodology.

1 **3. Transmission Substation Plan**

2 As discussed in Section II.C.2.c), the Transmission Substation Plan (TSP) consists of the
 3 Subtransmission Lines Plan, the A-Bank Plan and the Subtransmission VAR Plan. Based on SCE’s most
 4 recent analysis using the peak load assumptions from the IEPR forecast, SCE’s Subtransmission VAR
 5 Plan has not identified any projects within the GRC window.

6 Each year, SCE develops transmission and distribution system plans that describe the
 7 projects and programs required to expand, upgrade, and reconfigure the electrical grid over the next 10
 8 years. Table II-8 and Table II-9 below show 2019–2023 forecast capital expenditures for Transmission
 9 Substation Plan. These plans are further described below:

Table II-8
Transmission Substation Plan (TSP) Capital Expenditure Summary⁶⁷
(Total Company – Nominal \$000)

Line No.	Project Name	Prior	2019	2020	2021	2022	2023	Total
1	Subtransmission Lines Plan	221,706	63,228	100,425	82,619	67,189	13,545	548,712
2	A-Bank Plan	231,380	23,199	8,344	4,672	50,696	122,877	441,168
3	Total Transmission Substation Plan (TSP)	453,086	86,427	108,769	87,291	117,885	136,422	989,880

Table II-9
Transmission Substation Plan (TSP) Capital Expenditure Summary
(CPUC-Jurisdictional – Nominal \$000)

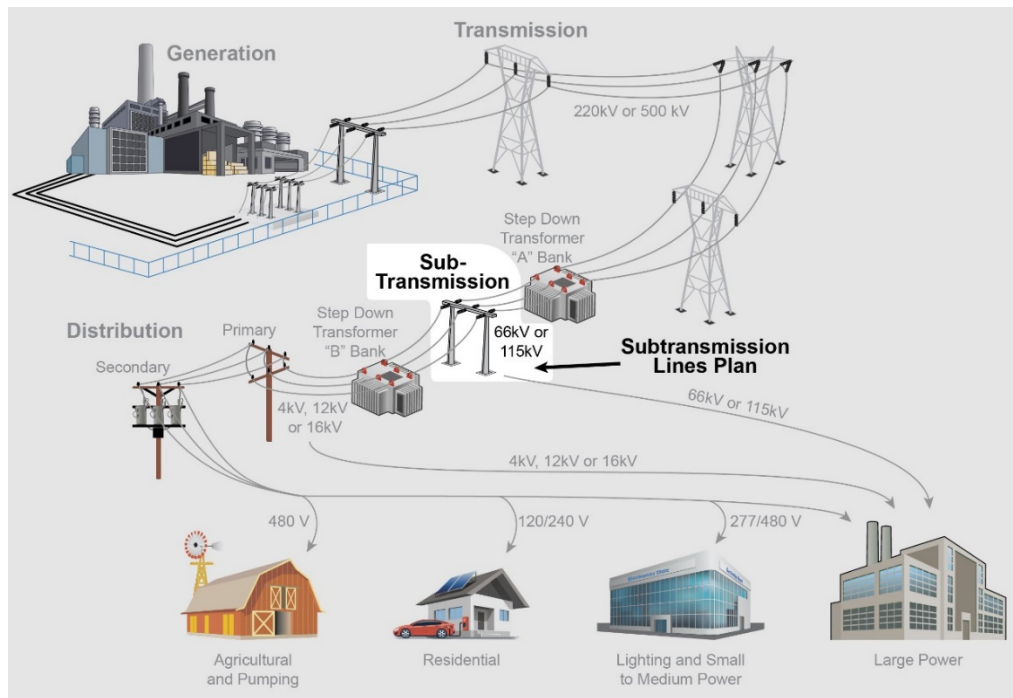
Line No.	Project Name	Prior	2019	2020	2021	2022	2023	Total
1	Subtransmission Lines Plan	221,706	63,228	100,425	82,619	67,189	13,545	548,712
2	A-Bank Plan	197,830	20,429	7,362	3,624	20,822	58,732	308,799
3	Total Transmission Substation Plan (TSP)	419,536	83,657	107,787	86,243	88,011	72,277	857,511

⁶⁷ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 27 - 227 – Capital Detail by WBS Element for Transmission Substation Plan.

1 a) **Subtransmission Lines Plan**

2 The Subtransmission Lines Plan focuses on SCE’s 66 kV and 115 kV
3 subtransmission lines to ensure safe and reliable service to customers. Figure II-17 illustrates the
4 pertained SCE’s facility that this section of the testimony addresses.

Figure II-17
Subtransmission Lines Plan



5 Table II-10 and Table II-11 below provide the total SCE and CPUC-jurisdictional
6 Subtransmission Lines Plan capital forecasts.

Table II-10
Subtransmission Lines Plan Capital Expenditure Summary^{68,69,70,71}
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	8002	El Nido-Lennox-Polaris-Yukon 66 kV Subtransmission Line	Jan 2019	6,859	82	-	-	-	-	6,941
2	7764	Vestal-Columbine-Delano-Earlmart 66 kV	Mar 2019	3,595	531	-	-	-	-	4,126
3	7851	Porterville-Woodville 66 kV	May 2019	326	2,722	-	-	-	-	3,048
4	8003	El Nido-Felton-La Cienega 66 kV Subtransmission Line	Dec 2019	156	1,607	1,642	-	-	-	3,405
5	6030	Valley-Ivyglen 115 kV	May 2020	25,441	10,615	74,819	54,849	43,202	676	209,602
6	7505	La Cienega-Beverly-Culver 66 kV	Jun 2020	4,789	3,445	2,895	-	-	-	11,129
7	5346	New Valley South Subtransmission Line	July 2020	14,575	30,896	9,149	766	-	-	55,386
8	8122	El Nido-Lennox 66 kV Subtransmission Line	Dec 2020	102	2,845	6,805	3,297	-	-	13,049
9	8151	Irvine 66/12 kV Substation	Jun 2022	-	53	752	2,954	2,954	-	6,713
10	8251	Saugus-Newhall #1 & Saugus-Newhall #2 66 kV Subtransmission Line	Jun 2022	-	-	30	2,378	8,811	8,819	20,038
11	6871	Rector-Riverway No. 2 66 kV	Dec 2022	-	177	480	15,614	9,446	-	25,717
12	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line	Jun 2023	-	-	-	332	912	1,844	3,088
13	8252	Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line	Jun 2023	-	-	-	515	1,715	2,059	4,289
14		<i>Subtotal of Subtransmission Lines Plan</i>		55,843	52,973	96,572	80,705	67,040	13,398	366,531
15		Projects with CPUC-jurisdictional cost < \$3M		3,837	3,573	518	1,767	149	0	9,844
16		Projects with operating date outside of GRC window		162,026	6,682	3,335	147	0	147	172,337
17		Total Subtransmission Lines Plan		221,706	63,228	100,425	82,619	67,189	13,545	548,712

⁶⁸ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 228 - 313 – Subtransmission Line Projects.

⁶⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 314 - 315 – Subtransmission Line Projects Less Than \$3M CPUC-jurisdictional Costs.

⁷⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 316 - 317 – Subtransmission Line Projects Outside the GRC Window.

⁷¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 318 - 319 – PIN Mapping to Capital Details.

Table II-11
Subtransmission Lines Plan Capital Expenditure Summary
(CPUC-Jurisdictional – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	8002	El Nido-Lennox-Polaris-Yukon 66 kV Subtransmission Line	Jan 2019	6,859	82	-	-	-	-	6,941
2	7764	Vestal-Columbine-Delano-Earlimart 66 kV	Mar 2019	3,595	531	-	-	-	-	4,126
3	7851	Porterville-Woodville 66 kV	May 2019	326	2,722	-	-	-	-	3,048
4	8003	El Nido-Felton-La Cienega 66 kV Subtransmission Line	Dec 2019	156	1,607	1,642	-	-	-	3,405
5	6030	Valley-Ivyglen 115 kV	May 2020	25,441	10,615	74,819	54,849	43,202	676	209,602
6	7505	La Cienega-Beverly-Culver 66 kV	Jun 2020	4,789	3,445	2,895	-	-	-	11,129
7	5346	New Valley South Subtransmission Line	July 2020	14,575	30,896	9,149	766	-	-	55,386
8	8122	El Nido-Lennox 66 kV Subtransmission Line	Dec 2020	102	2,845	6,805	3,297	-	-	13,049
9	8151	Irvine 66/12 kV Substation	Jun 2022	-	53	752	2,954	2,954	-	6,713
10	8251	Saugus-Newhall #1 & Saugus-Newhall #2 66 kV Subtransmission Line	Jun 2022	-	-	30	2,378	8,811	8,819	20,038
11	6871	Rector-Riverway No. 2 66 kV	Dec 2022	-	177	480	15,614	9,446	-	25,717
12	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line	Jun 2023	-	-	-	332	912	1,844	3,088
13	8252	Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line	Jun 2023	-	-	-	515	1,715	2,059	4,289
14		<i>Subtotal of Subtransmission Lines Plan</i>		55,843	52,973	96,572	80,705	67,040	13,398	366,531
15		Projects with CPUC-jurisdictional cost < \$3M		3,837	3,573	518	1,767	149	0	9,844
16		Projects with operating date outside of GRC window		162,026	6,682	3,335	147	0	147	172,337
17		Total Subtransmission Lines Plan		221,706	63,228	100,425	82,619	67,189	13,545	548,712

(1) Program Description

The Subtransmission Lines Plan provides adequate 66 kV or 115 kV line capacity in each of SCE’s subtransmission networks to serve forecast peak loads at SCE’s B-substations. Through power flow studies, the capacities of each subtransmission line are evaluated to determine if they can be safely operated within (1) established loading limits under normal conditions with all facilities in service (“Base Case”), and (2) under abnormal conditions when equipment is out of service due to planned or unplanned outages (“Likely Contingency”). These power flow studies also evaluate whether adequate voltage can be maintained under normal and abnormal conditions. When SCE forecasts that a subtransmission line will become overloaded or that it cannot maintain adequate voltage as a result of the power flow studies, operational solutions are first considered, similar to the distribution planning process. This includes determining if existing infrastructure can transfer electric power from a highly loaded subtransmission line to a less loaded one. When other options are not available, a capital project is initiated to expand, upgrade, or reinforce the system. Typical projects include replacing existing subtransmission lines and/or circuit breakers with higher capacity ones, constructing new lines, and installing 66 kV or 115 kV capacitor banks at B-substations. These facilities are illustrated in the highlighted portion of Figure II-17 (Subtransmission Lines Plan). The Subtransmission Lines Plan

1 includes loop-in projects, reconductor or recable projects, new line projects and voltage-driven capacitor
2 projects.

3 Without a comprehensive plan, SCE risks loading its 66 kV and 115 kV
4 subtransmission lines beyond their capabilities as the peak demand for electricity continues to increase
5 in some areas within SCE's service territory. This could ultimately result in failures of overhead and/or
6 underground subtransmission lines and service interruptions to tens of thousands of customers over local
7 geographic areas.

8 SCE's comprehensive Subtransmission Lines Plan includes four different
9 types of projects described in section below:

10 (a) **Loop-In or Reconfiguration Projects**

11 SCE has an obligation to provide safe and reliable power to its
12 customers. Over time, as load increases in an area, there may be a time when an additional
13 subtransmission line must be brought into a B-substation. Many times this can be accomplished by
14 looping an existing tapped line into and out of a B-substation, creating two new subtransmission lines.
15 Looping the existing line into a substation implies that there will be one line coming into the substation
16 and another leaving the substation creating two new lines from the one previous existing line.
17 Looping an existing line is often more economical than construction a new subtransmission line and
18 typically provides a second, different source line into the B-substation improving reliability to the
19 B-substation.

20 A reconfiguration project typically involves rearranging the
21 subtransmission lines near the substation. This could involve changing a Preferred/Emergency
22 configuration to a paralleled configuration or installing a new switchrack upon which multiple
23 subtransmission lines can be terminated. The loop-in/reconfiguration projects are described below.
24 The costs for these projects are 100 percent CPUC-jurisdictional.

Table II-12
Loop-In/Reconfiguration Projects

Line No.	Project No.	Project Name	Project Scope	Operating Date	Project Type	Total Cost
1	4891	Arrowhead 115/33 kV Substation	Loop in project and reconfigure 115 kV subtransmission line arrangement.	Feb 2021	Reliability	1,860

**Table II-13
Reconductor and Recable Projects**

Line No.	Project No.	Project Name	Project Scope	Operating Date	Project Type	Program/Project Type	Overload	Total Cost
1	8002	El Nido-Lennox-Polaris-Yukon 66 kV Subtransmission Line	Reconductor the El Nido and Lennox legs of the El Nido-Lennox-Polaris-Yukon 66 kV underground portions from 1750 KCMIL AL to 3000 KCMIL Cu. The El Nido underground portion is approximately 0.5 mile and the Lennox underground portion is approximately 1.5 mile. Recabling the adjacent La Cienega-El Nido 66 kV Subtransmission Line that shares the same duct work. Replace the CO-8 relays at El Nido Substation on the Lennox-Polaris-Yukon 66 kV Subtransmission Line with SEL-311C	Jan 2019	Likely Contingency (N-2)	STL/Reconductor	103%	6,941
2	7764	Vestal-Columbine-Delano-Earlimart 66 kV	Reconductor 9.7 miles of 2/0 BC to 954 SAC	Mar 2019	Basecase and Likely Contingency	STL/Reconductor	102.7% base case	4,126
3	7851	Porterville-Woodville 66 kV	Reconductor 6.6 miles of 2/0 BC to 954 SAC	May 2019	Likely Contingency	STL/Reconductor	102%	3,048
4	7505	La Cienega-Beverly-Culver 66 kV	Recable 6.1 miles of 1750 AL to 3000 CU on four line segments	Jun 2020	Basecase and Likely Contingency	STL/Recable	106.5% 2018	11,129
5	8151	Irvine 66/12 kV Substation	Upgrade Switchrack, MEER and Replace 66 kV CB Pos. No. 6 (CB# 14) from 1200 A to 2000 A	Jun 2022	Likely Contingency	STL/Reconductor	102% 2018	6,713
6	8251	Saugus-Newhall #1 & Saugus-Newhall #2 66 kV Subtransmission Line	Reconductor 4.95 mi of 1750 XLP Underground Cable with 3000 AL.	Jun 2022	Likely Contingency	STL/Recable	102% 2022	20,038
7	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line	Reconductor 4800 ft (0.9 mi) of 4/0 CU and 6865 ft (1.3 mi) of 336 ACSR to 954 SAC in the Saugus leg	Jun 2023	Likely Contingency	STL/Reconductor	100.5% 2023	3,088
8	8252	Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line	Rebuild 1.82 miles of 4/0 CU with 954 SAC in the Pitchgen leg	Jun 2023	Likely Contingency	STL/Reconductor	100.03% 2023	4,289

Table II-14
New Subtransmission Line Projects
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Project Scope	Operating Date	Project Type	Overload	Total Cost
1	8003	El Nido-Felton-La Cienega 66 kV Subtransmission Line	Construct 0.5 mile of 3000 Cu and 0.1 mile of 954 SAC into Felton Substation	Dec 2019	Likely Contingency	102% 2019	3,405
2	6030	Valley-Ivyglen 115 kV	Construct a new Valley-Ivyglen 115 kV Subtransmission Line Project with 25.9 miles of 954 SAC and 300 feet of 1750 Al.	May 2020	Basecase	109.8% 2019	209,602
3	5346	Valley South Subtransmission Project	Construct 15.4 miles of new 115 kV subtransmission line	Jul 2020	Likely Contingency	100.4% 2021	55,386
4	8122	El Nido-Lemnox 66 kV Subtransmission Line	Construct 5 mile of 954 SAC line	Dec 2020	Likely Contingency	136% 2020	13,049
5	6871	Rector-Riverway No. 2 66 kV	Construct a new 66 kV subtransmission line 8.5 miles of 954 SAC and 1 mile of 3000 kernil Al.	Dec 2022	Likely Contingency	101.6% 2022	25,717

1 (d) **Voltage-Driven Projects**

2 There are three subtransmission capacitor projects required to
3 correct greater than 5 percent voltage drop conditions during emergency Likely Contingency events.
4 These three projects are each under \$3 million.⁷²

5 (2) **Licensing Status of Subtransmission Lines Projects**

6 As discussed in Section II.D.1.c)(2)(d), Table II-15 below contains the
7 licensing and exemption information for each of Subtransmission Lines projects.

***Table II-15
Licensing and Exemption Status of Subtransmission Lines Projects***

Line No.	Project No.	Project	Operating Date	Preliminary Licensing Determination
1	8002	El Nido-Lennox-Polaris-Yukon 66 kV Subtransmission Line	Jan 2019	Exemption G
2	7764	Vestal-Columbine-Delano-Earlimart 66 kV	Mar 2019	Advice Letter Filed 9/18/2014
3	7851	Porterville-Woodville 66 kV	May 2019	Exemption G
4	8003	El Nido-Felton-La Cienega 66 kV Subtransmission Line	Dec 2019	Exemption G
5	6030	Valley-Ivyglen 115 kV	May 2020	PTC Granted
6	7505	La Cienega-Beverly-Culver 66 kV	Jun 2020	Exemption G
7	5346	Valley South Subtransmission Project	Jul 2020	PTC Granted
8	8122	El Nido-Lennox 66 kV Subtransmission Line	Dec 2020	GO 131-D Under Review
9	8151	Irvine 66/12 kV Substation	Jun 2022	Substation Modification
10	8251	Saugus-Newhall No.1 & Saugus-Newhall No.2 66 kV Subtransmission Li	Jun 2022	Exemption E
11	6871	Rector-Riverway No. 2 66 kV	Dec 2022	GO 131-D Under Review
12	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line	Jun 2023	Exemption G
13	8252	Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line	Jun 2023	Exemption B

8 (3) **Basis for Capital Expenditure Forecast**

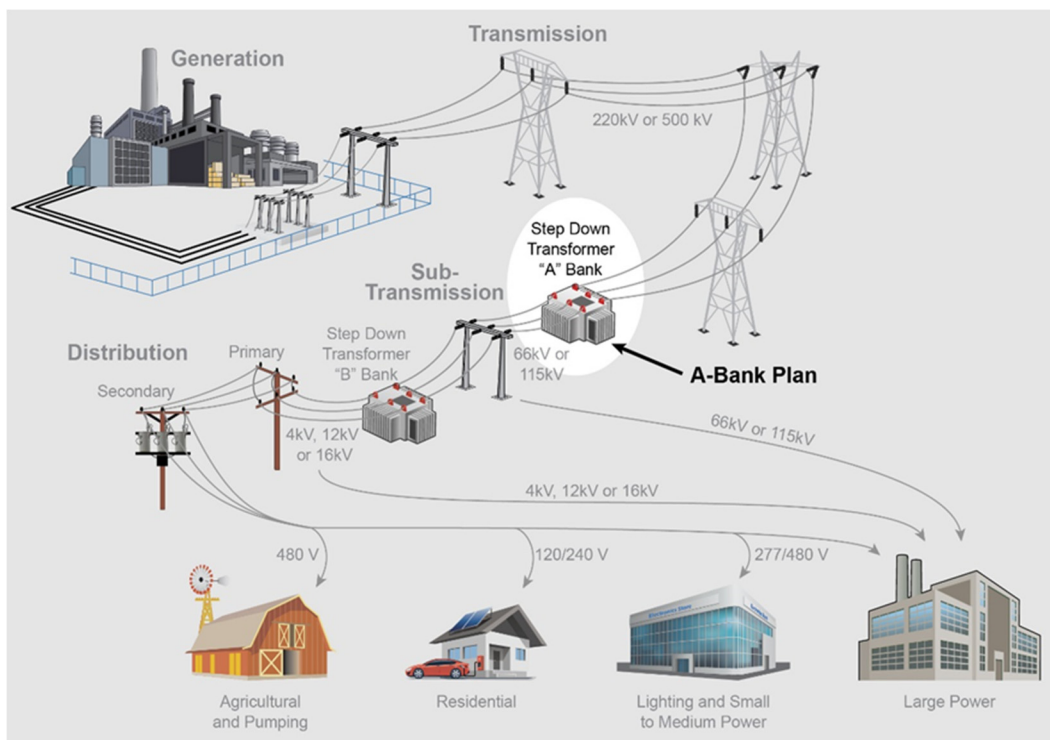
9 SCE has identified thirteen subtransmission lines projects with costs equal
10 to or greater than \$3 million and the total cost for these thirteen projects is \$311 million for years 2019-
11 2023. Additional projects with less than \$3 million in CPUC-jurisdictional costs are not discussed here,
12 but are included in workpapers. The total cost for these projects is \$10 million.

⁷² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 314 - 315 – Subtransmission Lines Projects Less Than \$3M CPUC-jurisdictional Costs.

1 **b) A-bank Plan**

2 The A-bank Plan focuses on SCE’s transmission substation capacity to ensure
3 safe and reliable service to customers. Figure II-18 illustrates the pertained SCE’s facility that this
4 section of the testimony addresses.

Figure II-18
A-Bank Plan



5 Table II-16 and Table II-17 below provide the A-bank Plan total SCE and
6 CPUC-jurisdictional capital forecasts.

Table II-16
A-Bank Plan Capital Expenditure Summary^{73,74,75}
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	5383	Chino 220/66 kV	Dec 2019	42,365	9,773	1,002	2,672	-	-	55,812
2	7767	Johanna 220/66 kV	May 2020	10,265	7,044	-	-	-	-	17,309
3	7740	Del Amo 220/66 kV	Dec 2020	432	252	3,164	-	-	-	3,848
4		<i>Subtotal of A-Bank Plan</i>		53,062	17,069	4,166	2,672	0	0	76,969
5		Project with CPUC-jurisdictional cost < \$3M		0	60	738	0	0	0	798
6		Projects with operating date outside of GRC window		178,318	6,070	3,440	2,000	50,696	122,877	363,401
7		Total A-Bank Plan		231,380	23,199	8,344	4,672	50,696	122,877	441,168

Table II-17
A-Bank Plan Capital Expenditure Summary
(CPUC-Jurisdictional – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	5383	Chino 220/66 kV	Dec 2019	41,135	8,920	805	2,672	-	-	53,532
2	7767	Johanna 220/66 kV	May 2020	10,265	7,044	-	-	-	-	17,309
5	7740	Del Amo 220/66 kV	Dec 2020	432	252	3,164	-	-	-	3,848
6		<i>Subtotal of A-Bank Plan</i>		51,832	16,216	3,969	2,672	-	-	74,689
7		Project with CPUC-jurisdictional cost < \$3M		-	60	738	-	-	-	798
8		Projects with operating date outside of GRC window		145,998	4,153	2,655	952	20,822	58,732	233,312
9		Total A-Bank Plan		197,830	20,429	7,362	3,624	20,822	58,732	308,799

⁷³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 320 - 333 – A-Bank Projects.

⁷⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 334 - 335 – A-Bank Projects Less Than \$3M CPUC-jurisdictional Costs.

⁷⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 336 - 337 – A-Bank Projects Outside the GRC Window.

1 **(1) Project or Program Description**

2 The objective of the A-bank plan is providing adequate capacity at each
 3 transmission substation to serve forecast peak loads under normal or base case conditions.
 4 These forecast loads represent the maximum demand for the highest expected temperature within a five-
 5 year period, referred to as a one-in-five year heat storm condition. SCE’s planning criteria require a
 6 thorough review of SCE’s facilities and the impact of peak demands under both normal conditions with
 7 all facilities in service, and emergency conditions, referred to as Likely Contingency conditions, when
 8 critical equipment is out of service.

9 When SCE forecasts that an A-bank transformer will become overloaded
 10 within the ten-year planning horizon, SCE evaluates whether existing infrastructure can be utilized to
 11 balance electric power between highly loaded substations and substations with additional reserve
 12 margins. If this cannot be achieved, a project to expand, upgrade, or reinforce SCE system is initiated.
 13 Typical projects include installing new A-bank transformers at existing substations, replacing existing
 14 transformers with higher capacity units, replacing other existing equipment such as switchracks and
 15 circuit breakers, and installing new A-substations.

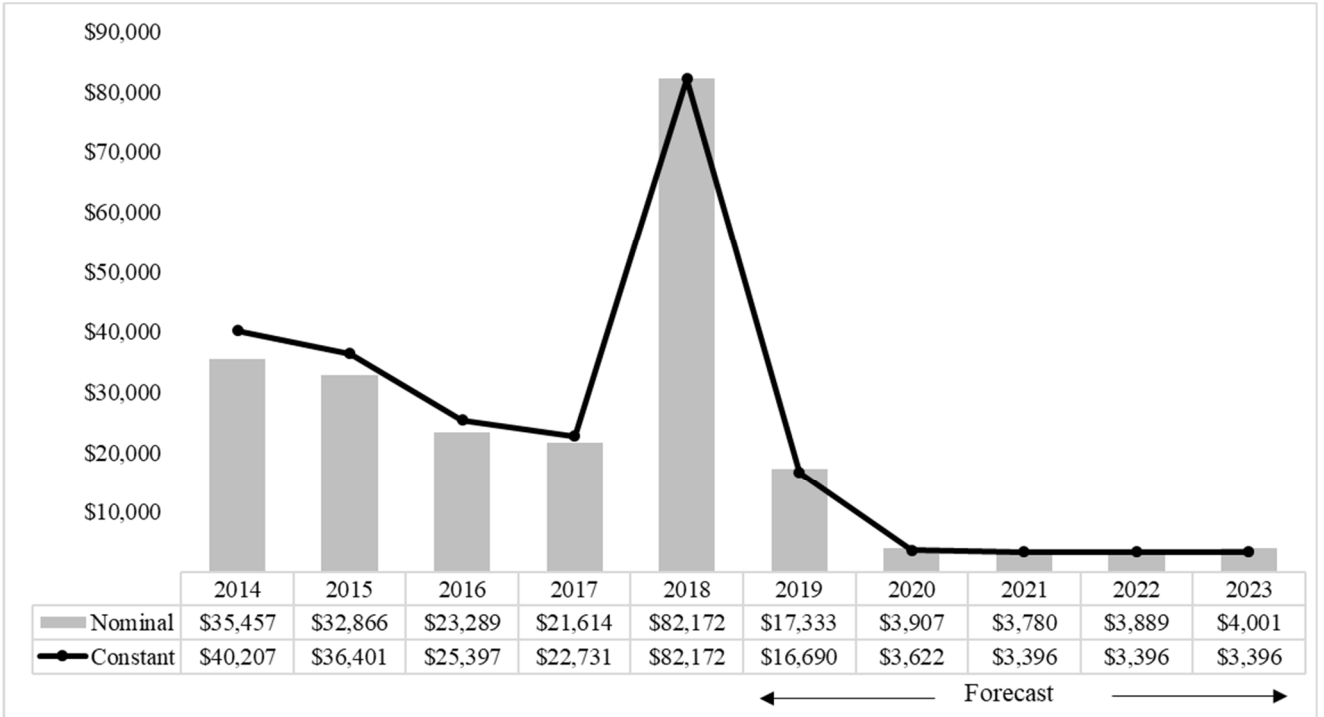
Table II-18
A-Substation Capacity Projects

Line No.	Project No.	Project Name	Project Scope	Operating Date	Project Type	Overload	Total Cost
1	5383	Chino 220/66 kV	Install a fourth 280 MVA transformer and split the system. Install two new 28.8 MVAR 66 kV capacitors and rebuild the 66 kV switchrack.	Dec 2019	Base Case	101.9% 2019	55,812
2	7767	Johanna 220/66 kV	Install a new 280 MVA transformer to correct an N-1 Likely Contingency STELL overload. Extend 66 kV switchrack to install new transformer.	May 2020	Likely Contingency	101% 2020	17,309
3	7740	Del Amo 220/66 kV	Del Amo 220/66: Replace (40) 66 kV bus disconnect switches. Replace (2) sectionalizing disconnect switches. Replace (2) sectionalizing CBs. Reconductor 66kV A section bus from 2-1033 KCMIL to 3-2156 KCMIL. Reconductor 66kV C section bus from 2-1033 Kcmil	Dec 2020	Likely Contingency	125% 2019	3,848

16 **(2) Licensing for A-bank Projects**

17 As discussed in Section II.D.1.c)(2)(d), Table II-19 below contains the
 18 licensing and exemption information for each of A-bank Plan projects.

Figure II-19
Distribution Plant Betterment Capital Expenditure Summary
WBS Element CET-PD-LG-PB⁷⁶
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) Program Description and Need for Activity

Plant Betterment is an activity that performs system improvements and projects to address local needs that are not covered by the Distribution Circuit Upgrades (DCU) program. This activity can include projects to address changes in load profiles that drive local low voltage problems, new protection devices and switches needed for safety and reliability, new developments that require a single-phase circuit voltage where none exists, new street or freeway improvements that impact SCE’s electric infrastructure, and more.

One example of plant betterment work is facilities required to help ensure SCE is able to meet its obligation of providing adequate voltage within the allowable range as

⁷⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 338 - 340 – Capital Detail by WBS Element for Distribution Plant Betterment.

1 prescribed by SCE’s Commission-approved Rule 2.⁷⁷ In some areas customer load additions or changes
2 in distribution system configurations may lead to voltage violations and must be resolved quickly.
3 Installing voltage regulators, capacitors, or increasing the size of existing overhead conductors or
4 underground cables are typical solutions to remedy voltage issues.

5 Another example of plant betterment work includes distribution circuit
6 modifications that may be necessary for reliability, safety, or protection reasons. The distribution system
7 is dynamic and changes to it can occur frequently and quickly to meet the electrical needs of customers.
8 Over time and due to these changes, distribution circuits may require additional facilities to be installed
9 (e.g., switches, protective devices, etc.) to help ensure reliable and safe electrical service, along with
10 providing system operational flexibility. For example, to minimize the number of customers that may be
11 impacted when performing routine system maintenance, strategically located switches to sectionalize
12 and transfer load are required. Additionally, to minimize both the magnitude (number of customers
13 impacted) and the duration of unplanned outages, automatic reclosers⁷⁸ are also required in strategic
14 locations. Sometimes, particularly on longer distribution circuits and as circuit configurations change or
15 customer loads change, the location of the existing automatic reclosers are insufficient to perform the
16 needed functions. In these cases, SCE may install additional automatic reclosers. In other cases,
17 customer loads change, that requires the installation of new or upgraded devices.

18 A third example of a plant betterment addition is the modification of a
19 distribution circuit to allow for the transfer of load from one circuit to an adjacent circuit where the
20 current configuration of the circuitry would not allow it. As identified above, SCE’s distribution system
21 consists of a three-phase power system that provides electricity to customers through either three-phase
22 or single-phase service. The distribution circuits that deliver this power are configured as either three-
23 wire circuits or four-wire circuits. Three-wire circuits have three conductors only; one for each of the
24 three phases. Four-wire circuits have four conductors; one for each of the three phases and a fourth for a
25 neutral path. When single-phase service is required, it can be provided in either of two configurations:
26 “phase-to-phase” or “phase-to-ground.” Both configurations provide single-phase service to the

⁷⁷ D.97-10-087.

⁷⁸ Automatic reclosers are switches that have the capability to perform protection functions by being able to interrupt fault current in a manner similar to circuit breakers.

1 customer; however the connections necessary to provide the service are different and the voltage ratings
2 of the transformers providing the service are different.

3 When SCE identifies a load transfer from one circuit to another as the
4 preferred solution to addressing a projected loading issue, the two circuits must be compatible in their
5 configuration to perform the transfer (e.g., both four-wire circuits or both three-wire circuits). Should the
6 two circuits not have compatible configurations,⁷⁹ the addition of a fourth-wire is considered to make the
7 circuit configurations compatible. The addition of a fourth wire to an existing three-wire circuit can
8 often be a cost-effective alternative solution to other distribution circuit upgrades or new distribution
9 circuits.

10 Finally, another example of plant betterment investments include adding
11 infrastructure during street improvement plans or freeway crossings which provide SCE the opportunity
12 to underground facilities for future use at the time that the improvements are occurring rather than at a
13 later date. By leveraging the construction activities in progress, SCE is able to install underground
14 facilities that would otherwise be disruptive and costly to install at a later date, such as after street
15 paving and road closures are complete. Adding pathways (e.g., underground conduits) through bridges
16 or in freeway overpasses can also avoid these impacts when the facilities would become needed in the
17 future. Developers often work with SCE in these situations to allow for these plant betterment
18 investments to occur in an optimal and a cost-effective manner.

19 (2) **Basis for Capital Expenditure Forecast**

20 The Distribution Plant Betterment forecast expenditures include work
21 required to meet anticipated load growth causing voltage violations, for either reliability or safety and
22 protection reasons, and to meet contingency scenarios. Work in this category improves voltage profiles
23 to better serve customers by installing voltage regulators or increasing the size of conductor or cable.
24 Due to the diverse project scope, SCE does not forecast costs based on unit cost.

25 Figure II-19 above shows 2014–2018 recorded and 2019–2023 forecast
26 expenditures for the Distribution Plant Betterment program. Recorded expenditures in 2014 and 2015
27 are higher compared to expenditures in surrounding years due to the inclusion of upgrades completed to
28 meet regional needs identified by districts throughout the SCE service territory, upgrades to the Long

⁷⁹ Single-phase “phase-to-ground” connected load requires one phase conductor and a ground conductor (also known as a “fourth wire”) and are served by four-wire circuits. This load cannot be transferred to a three-wire circuit as it does not have a “fourth wire” or ground conductor necessary to provide appropriate voltage.

1 Beach secondary network system after the downtown area experienced long outage durations in 2015,
2 including the installation of vault cover restraints, and work similar to the Overhead Conductor Program
3 (OCP) before the program was created.

4 In 2018, recorded expenditures are higher compared to expenditures in
5 surrounding years primarily due to work related to Grid Resiliency before SCE officially established this
6 program and regional grid needs. As discussed in SCE-01, SCE needed to act with a sense of urgency in
7 2018 to address the wildfire threat; as such, SCE used the Plant Betterment program to record
8 expenditures until the grid resiliency program could be established with its own accounting needs.⁸⁰

9 The basis for the forecast looks at qualifying Plant Betterment historical
10 work between 2015-2018. Historical costs for the work similar to OCP, regional grid needs, Long Beach
11 secondary network upgrades, and the 2018 Grid Resiliency work are not included in the calculated
12 forecast for 2019–2023. In 2018 constant dollars, average expenditures over the 2015–2018 historical
13 period is \$16.7 million.⁸¹ We expect the forecast need to match the historical workload in this category
14 during the forecast period (excluding the previously mentioned adders in 2015 and 2018). However, due
15 to the Grid Resiliency effort, additional considerations needed to be taken due to the reduction in
16 resources. SCE anticipates to include all needed work for Distribution Plant Betterment in the 2024
17 General Rate Case. The total forecast expenditures from 2019–2023 is \$32.9 million (in nominal
18 dollars).⁸²

⁸⁰ See also Exhibit SCE-01, Volume 1 and Exhibit SCE-04, Volume 5.

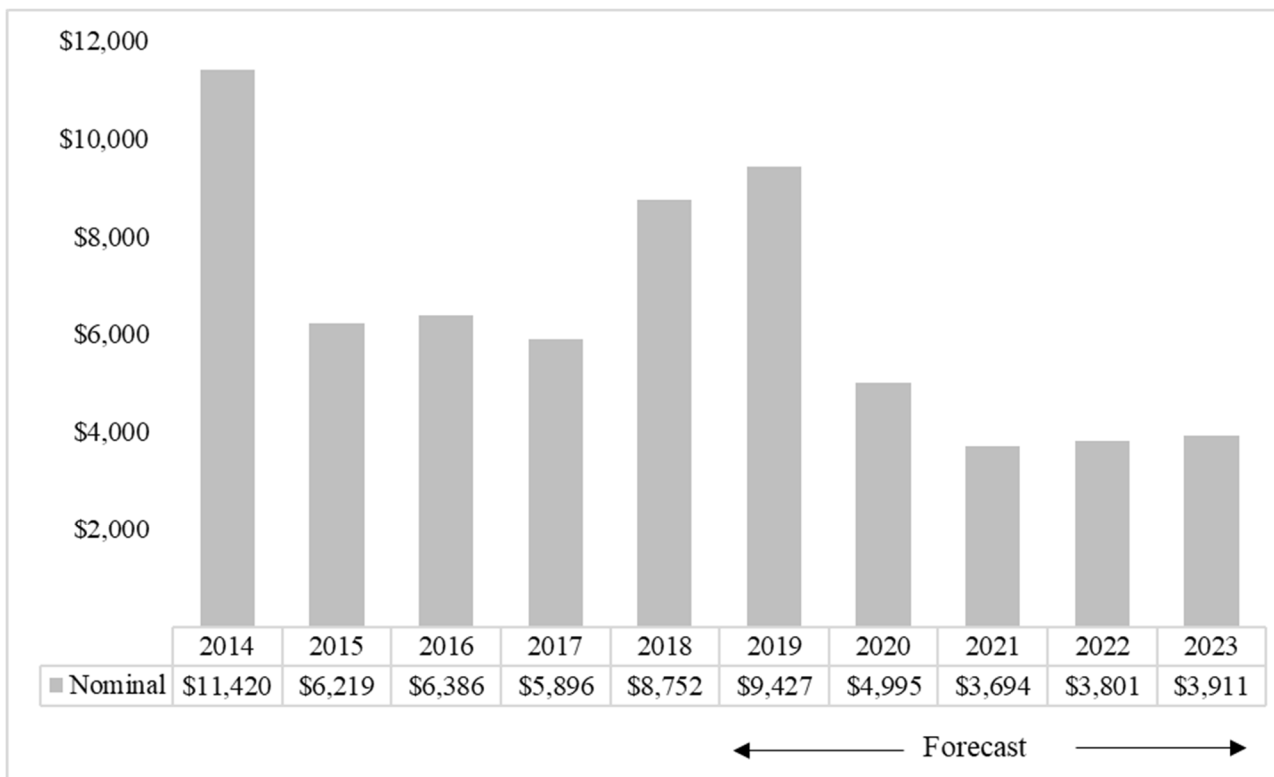
⁸¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 341 - 342 – Distribution Plant Betterment Forecast Methodology.

⁸² *Id.*

1 **b) New Capacitors**

2 Figure II-20 below shows 2014–2018 recorded and 2019–2023 forecast capital
3 expenditures for New Capacitors.

Figure II-20
New Capacitors Capital Expenditure Summary
WBS Element CET-ET-LG-NC⁸³
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



4 **(1) Program Description**

5 Reactive power demand increases as load continues to increase on the
6 system. Distribution capacitor banks supply reactive power (VAR) to the distribution system to maintain
7 acceptable power factor⁸⁴ and help maintain suitable voltage to serve customers. The program plans
8 installation of new capacitors on distribution circuits that have a reactive power (VAR) deficit.

⁸³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 343 - 344 – Capital Detail by WBS Element for New Capacitors.

⁸⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 345 - 348 – New Capacitors Forecast Methodology.

1 **(2) Basis for Capital Expenditure Forecast**

2 SCE’s forecast expenditures for 2019–2023, as shown in Figure II-20, are
3 based on estimated growth in VAR demand of each circuit on SCE’s distribution system and
4 corresponding numbers of capacitor banks that need to be installed to meet this VAR demand. The VAR
5 demand is calculated based on SCE’s peak load forecast and historical load characteristics of each
6 distribution circuit.⁸⁵ The capacitor bank cost is inclusive of all capital to complete an installation as it is
7 based on an average of historical closed work orders for completed capacitor installation projects.

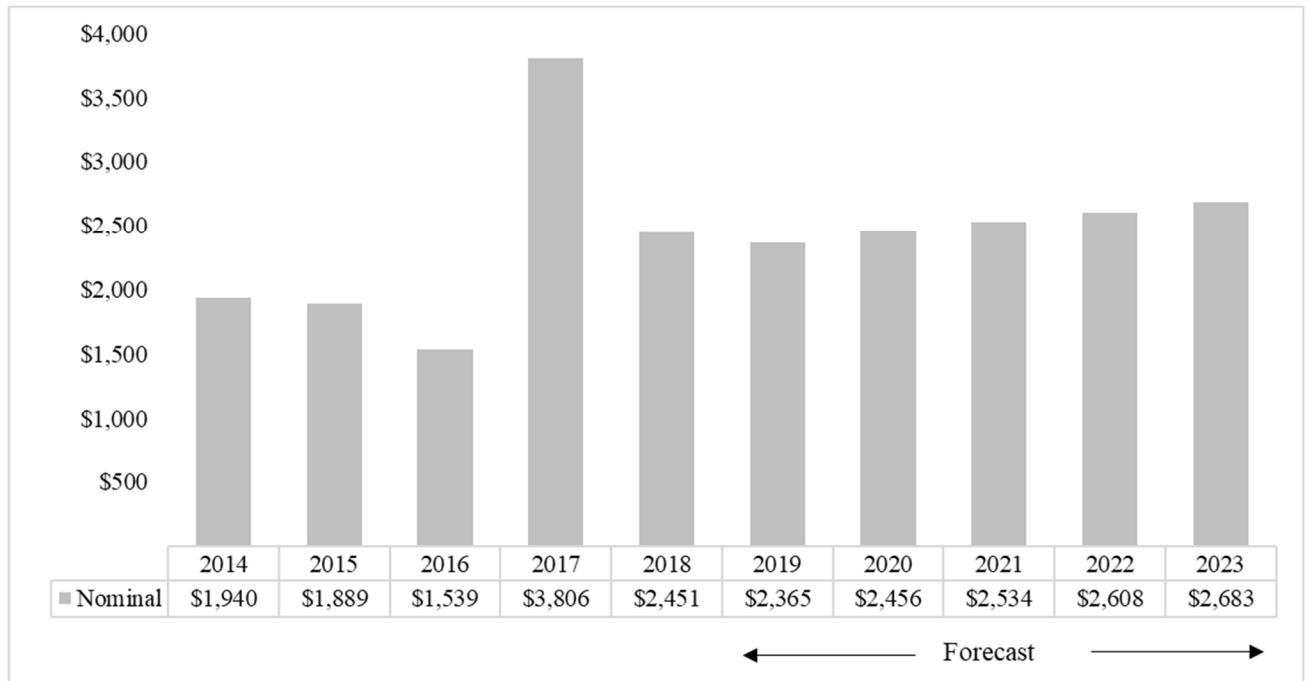
8 In addition to meeting estimated growth in VAR demand, SCE’s forecast
9 expenditures also include installing capacitors to address existing VAR deficit, such as on 33 kV
10 circuits. Due to unavailability of 33 kV rated capacitor banks, SCE was not able to completely meet
11 VAR needs of these circuits in previous years. To address these needs, SCE is expecting the
12 development of required components for 33 kV rated capacitor banks to be finalized and available for
13 standard installation in 2020-2021. The New Capacitors forecast includes anticipated work for these
14 capacitor banks beginning in 2021.

15 **c) Distribution Volt-VAR Control (DVVC) and Programmable Capacitor**
16 **Controller (PCC) Replacement Program**

17 Figure II-21 below shows the recorded cost in 2014-2018 and forecast capital
18 expenditure in 2019-2023.

⁸⁵ *Id.*

Figure II-21
Distribution Volt VAR Control & Programmable Capacitor Control Replacement Capital
Expenditure Summary
WBS Element CET-PD-LG-CV⁸⁶
Recorded 2014-2018/Forecast 2019-2023
(Total Company - Nominal \$000)



(1) Program Description and Need for Activity

The Programmable Capacitor Control (PCC) Replacement program and the associated Distribution Volt VAR Control (DVVC) algorithm are implemented at SCE to allow for Conservation Voltage Regulation⁸⁷ (CVR) to decrease energy consumption, while maintaining reliable voltage delivery⁸⁸ to SCE customers.

Programmable capacitor controls are specifically designed for the control and automation of pole-mounted and pad-mounted switched capacitor banks in SCE’s distribution

⁸⁶ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 349 - 351 – Capital Detail by WBS Element for DVVC.

⁸⁷ Conservation Voltage Regulation and Conservation Voltage Reduction are used interchangeably in the utility industry. CVR is the ratio between percentage of energy reduction to percentage voltage reduction.

⁸⁸ Voltage as designated in the ANSI C84.1 standard and modified by California Rule 2.

1 system. A capacitor control's basic function is to provide remote capability⁸⁹ to open or close switches
2 on capacitor banks based on established engineering settings for voltage, temperature, and/or time bias
3 control strategies. PCCs are an important asset to the implementation of CVR and play an integral part
4 for the DVVC algorithm. SCE's PCC Replacement program replaces failed or non-functional PCCs and
5 upgrades obsolete PCCs in support of the DVVC algorithm. PCCs are also used for automating existing
6 installed capacitor banks⁹⁰ to provide additional telemetry capability as well as reliability to the system.

7 The DVVC program is implemented at SCE as a centralized control
8 algorithm designed to achieve an optimal voltage and VARs across all circuits fed by substation
9 transformers. As shown in Figure II-22 below, supervisory-controlled distribution substation capacitors
10 and existing standard automated distribution field capacitors on distribution circuits are leveraged to
11 provide input for the DVVC algorithm to make real-time decisions by switching on or off the above-
12 mentioned field and substation capacitors. As a result of the optimization, the system average voltage is
13 reduced; which in turn reduces energy consumption while maintaining overall customer service voltage
14 requirements.⁹¹ SCE DVVC program began in 2016, and successfully implemented the DVVC
15 algorithm to 297 substations. As a result of the DVVC algorithm implementation, SCE has demonstrated
16 that this centralized control strategy resulted in a CVR of 1.07 (0.6% in energy reduction and 0.56%
17 voltage reduction) in 2016 and 2017, 1.33 (0.8% energy reduction and 0.6% voltage reduction) in 2018.
18 As the CVR program evolves, the need for continued improvement and expansion of the current
19 algorithm to the rest the substations across service territory will further improve CVR benefits.⁹²

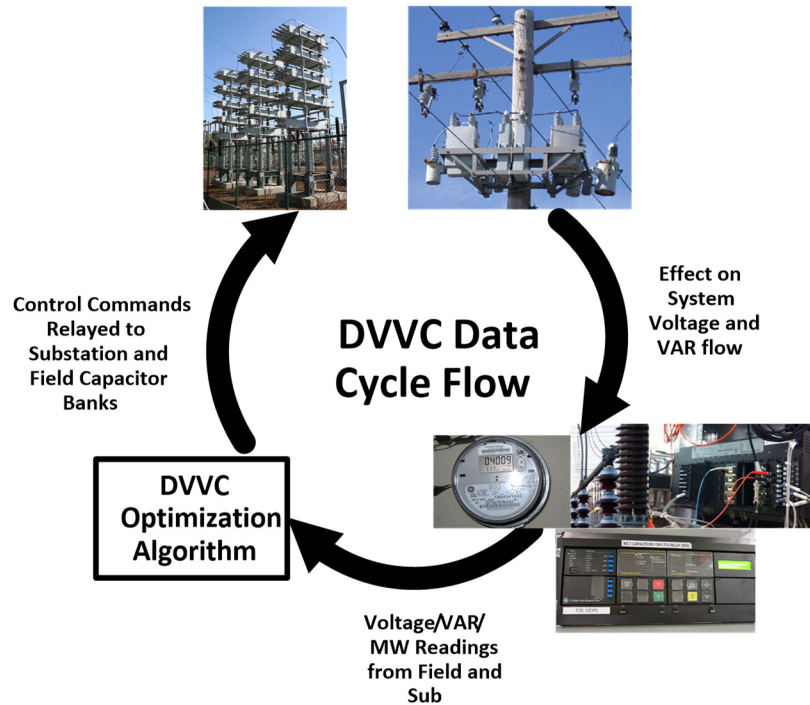
⁸⁹ System telemetry at a capacitor location is provided via the Distribution Management System (DMS) such as device status, remote capability, voltage reading, harmonic readings, internal settings, and provides the ability for operators to remotely modifying the PCC internal settings over the air via existing Netcomm system.

⁹⁰ Existing installed capacitor banks that do not have remote control capability are often called "fixed capacitor banks".

⁹¹ DVVC optimizes customer voltage profiles through dynamic switching of substation and field capacitors. Engineering analysis determines the voltage thresholds for DVVC algorithm at different loading conditions (summer peak vs. winter peak load), while maintaining customer voltage within its required voltage range.

⁹² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 352 - 359 – DVVC and PCC Replacement Program Details.

**Figure II-22
DVVC Optimization Process**



(2) Basis for Capital Expenditure Forecast

SCE PCC replacement forecast is based on recorded replacement from 2014-2018. In 2016 and 2017, with the increased visibility from the implementation of the DVVC algorithm, the PCC replacement ramped up due to the number of failed or non-functioning PCCs and upgrade obsolete PCCs in order to support the DVVC algorithm. From the historical recorded replacement and cost, this is used to derive the forecasted PCC replacement forecast and unit cost.

Table II-20 below shows the capital expenditure forecast for the DVVC and PCC replacement program in 2019-2023.

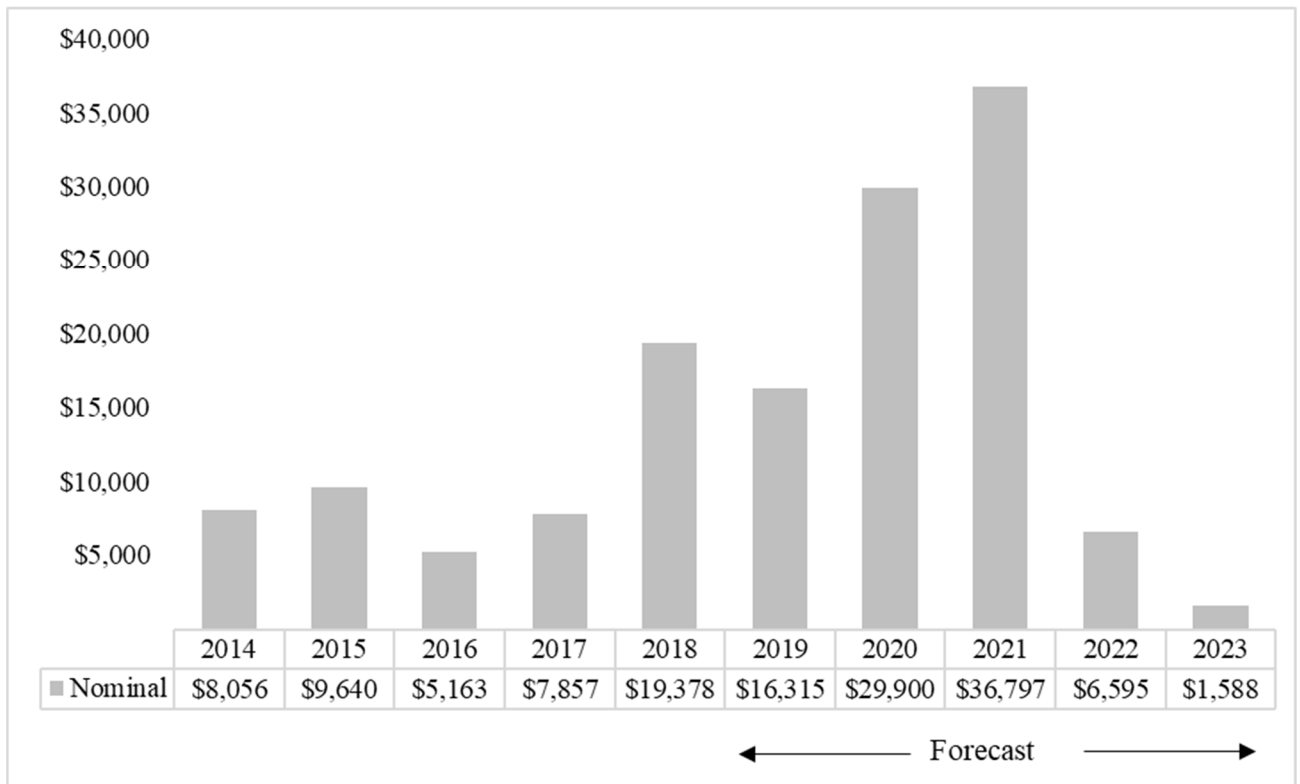
- Including 33kV substations that will have voltage and VAR support apparatus with the deployment of 33kV automated capacitors.

SCE's CVR program will continue to improve the already-implemented DVVC algorithm systems, as well as expanding to stations with active voltage regulation such as Load Tap Changers (LTC), Voltage Regulators, newly-automated distribution substation(s), and newly installed distribution substation(s). The CVR program will focus on stations with active voltage controls to implement DVVC algorithm to all automated substations across territory. The intention for expanding the DVVC algorithm is to stretch the CVR benefits while collecting and refining LTC, voltage regulator settings and prepare for the implementation of DVVC algorithm into advanced solution such as ADMS in a near future. Prior to commissioning DVVC for a substation, all settings for transformer LTC, line and field voltage regulators settings must be collected for engineering analysis. If the collected settings need to be updated, SCE Substation Construction & Maintenance technician must perform these settings update. This is to ensure the cohesiveness of the transformer LTC, voltage regulators operation align with DVVC optimization. Additionally, all system operators and Substation Construction & Maintenance technicians must understand how to safely operate associated substation equipment. This requires that DVVC-related substation operating procedures and instructions be updated to mitigate any potential safety concerns that could arise during normal maintenance activities. Procedures requiring update include circuit breaker clearing, circuit breaker analysis, and standard station instructions for each DVVC-related substation commissioned. Additionally, SCE Power System Control (PSC) group update DVVC algorithm accordingly in Distribution Management System (DMS) and Energy Management System (EMS) to reflect the actual locations of station and field capacitors.

d) **Substation Equipment Replacement Program (SERP)**

Figure II-23 below shows 2014–2018 recorded and 2019–2023 forecast capital expenditures for SERP.

Figure II-23
Substation Equipment Replacement Program Capital Expenditure Summary
WBS Element CET-ET-LG-SU⁹⁷
Recorded 2014-2018/Forecast 2019-2023
(Total Company – Nominal \$000)



(1) **Program Description**

The Substation Equipment Replacement Program (SERP) replaces substation equipment identified to exceed their protection ratings to interrupt fault current. SCE identifies substation circuit breakers projected to exceed short circuit duty interrupting capabilities by comparing each circuit breaker’s short circuit duty rating with the potential fault current that circuit breaker will have to interrupt. Circuit breakers attempting to interrupt fault current that exceed ratings

⁹⁷ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 360 - 361 – Capital Detail by WBS Element for Substation Equipment Replacement Program.

Table II-21
Substation Equipment Replacement Program
Circuit Breaker Counts

Voltage Class	2019	2020	2021	2022	2023
115 kV CBs	0	7	0	0	0
66 kV CBs	66	0	78	31	9
16 kV CBs	5	16	3	0	0
12 kV CBs	7	90	83	0	0
4 kV CBs	14	19	53	0	0
Total CBs to Replace	92	132	217	31	9

1 The forecast is developed from circuit breaker unit costs as a starting point
2 for planned circuit breaker replacements. Unit Cost averages are calculated for each voltage class of
3 circuit breakers for the period 2014-2018.⁹⁸ These are same unit costs used by the Substation
4 Infrastructure Replacement program in SCE-02 Volume 3, Section IV.B.1. The annual expenditures for
5 each circuit breaker are then split across the in-service year and the year prior.

6 As projects get closer to execution, additional details will factor into
7 project specific adjustments for materials and construction execution. The final forecast for 2019-2023 is
8 a mix of known adjustments for specific projects and unit costs for planned projects with operating dates
9 in 2021-2023.⁹⁹

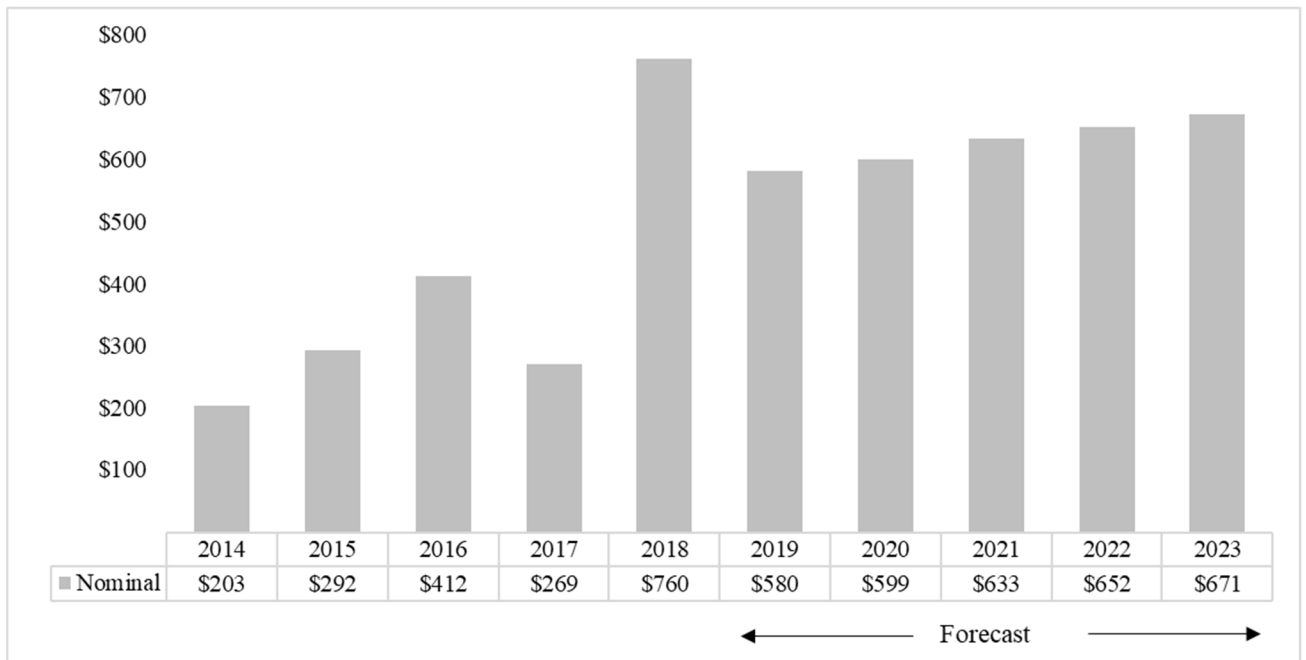
⁹⁸ Refer to WP SCE-02, Vol. 3, pp. 139 - 149 – CB and Xfmr Cost Forecast.

⁹⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 20 - 22 – Substation Equipment Replacement Program Forecast Methodology.

1 **5. Land Rights Management**

2 Figure II-24 below provides the recorded and forecast capital expenditures for Land
3 Rights Management.

Figure II-24
Land Rights Management Capital Expenditure Summary
WBS Element CET-RP-OT-VR¹⁰⁰
Recorded 2014 – 2018/Forecast 2019 – 2023
(Total Company – Nominal \$000)



4 SCE facilities will sometimes require passage along routes through property owned by
5 another party. This category covers expenditures for various rights of way required for SCE facilities to
6 pass through these locations. The 2019 – 2023 expenditure is estimated at approximately \$3.1 million.

7 The capital spending is required to cover costs associated with acquiring land rights not
8 specifically provided for by a project budget. Examples include acquiring new access roads to allow for
9 maintenance of existing facilities, acquisition of land rights over formerly government land that has been
10 patented and sold to private parties, and acquisition of fee property to support operation and
11 maintenance work.

¹⁰⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. II – Book B - pp. 362 - 363 – Capital Detail by WBS Element for Land Rights Management.

1 Since the purpose of this request is to cover miscellaneous acquisitions that are not
2 associated with a specific project or major project, whereby a land right must be acquired and the cost
3 associated with the acquisition was not expected for the year. The forecast is based on an operating level
4 that has generally covered historical and anticipated expenses in the forecast period.

5 Example expenditures are permit-to-license conversion, load growth and when no documented
6 transmission rights are found. The forecast would cover all costs associated with acquiring the land
7 right, document preparation, valuation, negotiations, and survey/mapping.

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III.

TRANSMISSION PROJECTS

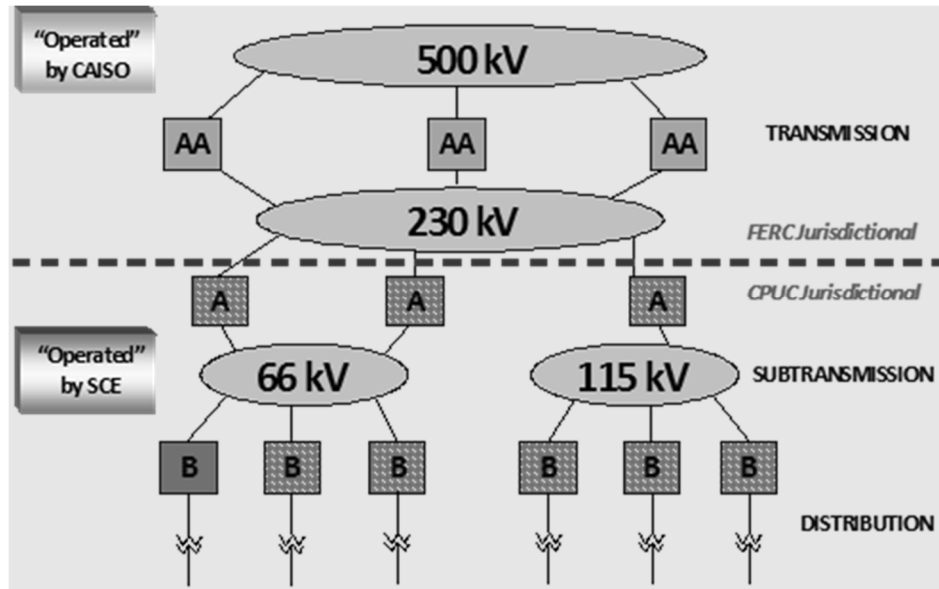
A. Overview

The Transmission Projects Business Plan Element includes work SCE completes on its high voltage transmission system (500 kV and 220 kV). SCE's high voltage transmission system, which includes transmission lines, substations, and 500/220 kV transformers, are under the operational control of the California Independent System Operator (CAISO) and subject to Federal Energy Regulatory Commission (FERC) jurisdiction. In order to sustain system reliability and flexibility, and meet our customers' future needs, SCE must continue to maintain, expand, and improve the transmission system. The transmission system must be designed to handle fluctuation in load, generation, and imports, and withstand disturbances from outages, storms, and other events.

SCE's remaining electric system, with the exception of two subtransmission systems,¹⁰¹ are under the operational control of SCE and within CPUC jurisdiction. Figure III-25 below illustrates the general jurisdictional split between the CPUC and FERC.

¹⁰¹ The two subtransmission systems under the operational control of the CAISO (as they operate in parallel with the CAISO controlled transmission system) are: (1) the Antelope-Bailey 66 kV System, and (2) the Victor-Kramer 115 kV System.

Figure III-25
General Jurisdictional Split Between CPUC and FERC



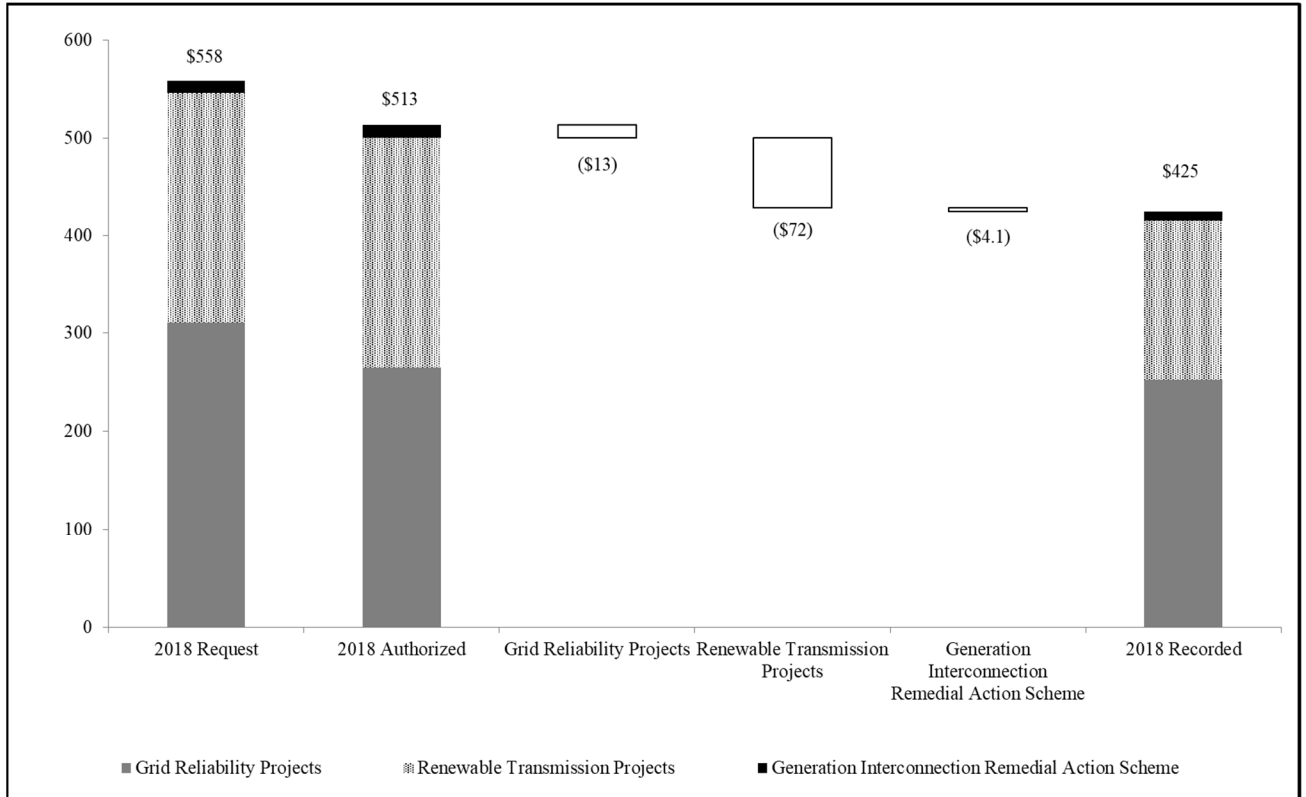
B. 2018 Decision

1. Comparison of Authorized 2018 to Recorded

Pursuant to the 2018 GRC Decision, SCE provides the following comparison between 2018 authorized and recorded expenditures;¹⁰² Figure III-26 shows the comparison for Transmission Projects.

¹⁰² D.19-05-020, Ordering Paragraph 22, pp. 441-442.

Figure III-26
Transmission Projects
2018 GRC Authorized Variance Summary 2018 Capital¹⁰³
(Total Company - Nominal \$Millions)



1 For Renewable Transmission Projects, SCE spent \$72 million less than authorized in
 2 2018. The largest portion of the variance was \$41 million related to the West of Devers Upgrade
 3 Project and this amount is 100% FERC jurisdictional. Actual expenditures for the West of Devers Upgrade
 4 Project were lower than originally forecast in the 2018 GRC due to lower market prices as bids were
 5 awarded and execution delays arising from licensing and permitting issues. The other primary driver of
 6 the variance was due to the deferral of the second Colorado River Substation AA-bank project.
 7 As project commencement is triggered when enough generation customers interconnect to the
 8 substation, customer project withdrawals in the cluster study process pushed the project start date (and
 9 corresponding expenditures) from the date originally projected in the 2018 GRC.

¹⁰³ Refer to WP SCE-07 Vol. 01. – Capital Authorized to Recorded.

1 For Grid Reliability Projects, the Mesa 500 kV Substation Project came in over the 2018
2 authorized amount by \$83 million (mostly FERC-jurisdictional) due to scope changes, additional project
3 support required for licensing and permitting delays, and unit price changes and escalation.

4 Conversely, the Eldorado-Lugo-Mohave Series Capacitor Project, which is listed as a Grid Reliability
5 project in this filing, experienced a \$77 million underrun due to the application needing to be amended
6 and re-filed from a Permit to Construction to a Certificate of Public Need and Necessity.

7 **C. Capital Expenditures - Transmission Projects**

8 While the majority of work for Transmission Projects fall within FERC jurisdiction, some of
9 these projects include components under CPUC jurisdiction – including upgrades to the underlying
10 subtransmission system and equipment supporting telecommunications, automation, and controls.¹⁰⁴
11 Both the total project and CPUC-jurisdictional expenditures forecast for these projects from 2019 to
12 2023 are shown in Table III-22 and Table III-23, respectively.

13 In general, a forecast and its associated expenditure plan are developed based on the scope of
14 work, the timing of execution and activities, the costs of goods and services, and the applicable
15 allocations, adjustments and/or allowances. Hence, the forecast reflects the cash requirement and reserve
16 for the planned activities in an accounting period. Allocations are indirect costs, including overheads,
17 attributable to execution. Adjustments and allowances are any informed changes to the forecast
18 incorporating identified risks and opportunities, lessons learned, spending or resource constraints,
19 studies of historic expenditures, and/or expert judgment.

20 Transmission Projects are categorized as Grid Reliability, Renewable Transmission, or
21 Generation Interconnection Remedial Action Scheme (RAS). Details for Grid Reliability and Renewable
22 Transmission Projects are provided Sections III.C.1 and III.C.2 below. However, the Generation
23 Interconnection RAS is not discussed further as there are no CPUC-jurisdictional capital expenditures
24 forecast from 2019 to 2023.

¹⁰⁴ See SCE-07, Vol. 1 for SCE's methodology for separating capital expenditures between FERC and CPUC jurisdiction.

Table III-22
Transmission Projects Capital Expenditure Summary^{105, 106}
(Total Company – Nominal \$000)

Line No.	Program/Project Category	Prior	2019	2020	2021	2022	2023	Total
1	Grid Reliability	596,348	235,708	345,041	258,409	193,899	113,378	1,742,783
2	Renewable Transmission	2,281,982	190,594	204,100	185,388	202,174	-	3,064,238
3	Generation Interconnection RAS	21,189	4,914	2,120	10,651	1,006	-	39,879
4	Forecast IT/Telecomm	-	2,675	-	-	11,819	9,601	24,094
5	Total Transmission Projects	2,899,520	433,891	551,260	454,448	408,897	122,978	4,870,994

Table III-23
Transmission Projects Capital Expenditure Summary
(CPUC-Jurisdictional – Nominal \$000)

Line No.	Program/Project Category	Prior	2019	2020	2021	2022	2023	Total
1	Grid Reliability	275,123	81,963	50,257	26,051	24,529	19,731	477,655
2	Renewable Transmission	459,726	5,779	5,638	5,443	8,857	-	485,443
3	Generation Interconnection RAS	-	-	-	-	-	-	-
4	Forecast IT/Telecomm	-	2,675	-	-	11,819	9,601	24,094
5	Total Transmission Projects	734,849	90,418	55,895	31,494	45,204	29,332	987,192

1. Grid Reliability Projects

The two tables below, Table III-24 (Total Company) and Table III-25 (CPUC-jurisdictional only), list the Grid Reliability Projects with over \$3 million in CPUC-jurisdictional capital expenditures that are expected to be completed and operational by the end of 2023. Details regarding forecast expenditures for Grid Reliability Projects with CPUC-jurisdictional costs of less than \$3 million each are provided in workpapers.¹⁰⁷

¹⁰⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 1 - 223 – Capital Detail by WBS Element for Transmission Projects.

¹⁰⁶ *Forecast IT/Telecomm* reflects projected telecommunication infrastructure expenditures supporting planned projects where no specific telecommunication scope estimates have been finalized at the time of filing.

¹⁰⁷ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 224 – 225 – Grid Reliability Projects Less Than \$3M CPUC-jurisdictional Costs.

Table III-24
Grid Reliability Projects Capital Expenditure Summary^{108,109,110,111}
CWBS Elements CET-ET-TP-RL
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	5450	Riverside Transmission Reliability Project	Dec 2023	8,951	1,992	18,997	104,396	117,847	58,554	310,738
2	7119	Walnut 230/66 kV: Bank on Circuit Breaker Project	Jun 2019	10,802	1,278	-	-	-	-	12,080
3	7546	Eldorado-Lugo-Mohave Series Capacitor Project	Dec 2021	58,895	39,448	84,032	39,602	32,501	728	255,206
4	7120	Chino 230/66 kV: Bank on Circuit Breaker Project	Dec 2020	37,736	1,891	3,648	2,989	-	-	46,265
5	7555	Mesa 500 kV Substation Project	Mar 2022	267,959	134,777	133,387	53,686	8,019	48,395	646,223
6	7727	Digital 395 Project	Dec 2020	2,672	1,934	2,946	-	-	-	7,552
7	7884	Cerritos Channel Transmission Line Relocation Project	Jul 2022	22,231	30,873	44,533	30,192	23,682	-	151,512
8	8104	Moorpark-Pardee 220 kV No. 4 Circuit	Dec 2020	179	15,567	14,778	7,077	-	-	37,601
9	8077	Annual Transmission Reliability Assessment Protection Upgrades	Mar 2021	11	534	14,888	3,721	-	-	19,155
10			<i>Subtotal</i>	<i>409,437</i>	<i>228,294</i>	<i>317,210</i>	<i>241,662</i>	<i>182,049</i>	<i>107,678</i>	<i>1,486,331</i>
11		Projects with CPUC-jurisdictional cost < \$3 M		17,019	6,010	27,831	16,747	11,850	5,700	85,156
12		Projects In-Service prior to 2019		169,892	1,404	-	-	-	-	171,296
13			Total	596,348	235,708	345,041	258,409	193,899	113,378	1,742,783

Table III-25
Grid Reliability Projects Capital Expenditure Summary
CWBS Elements CET-ET-TP-RL
(CPUC-Jurisdictional – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	5450	Riverside Transmission Reliability Project	Dec 2023	-	-	809	1,952	3,871	4,728	11,360
2	7119	Walnut 230/66 kV: Bank on Circuit Breaker Project	Jun 2019	6,373	754	-	-	-	-	7,127
3	7546	Eldorado-Lugo-Mohave Series Capacitor Project	Dec 2021	83	400	8,063	7,883	2,198	-	18,627
4	7120	Chino 230/66 kV: Bank on Circuit Breaker Project	Dec 2020	15,242	693	1,343	2,453	-	-	19,731
5	7555	Mesa 500 kV Substation Project	Mar 2022	141,630	48,675	11,509	1,264	935	15,003	219,016
6	7727	Digital 395 Project	Dec 2020	2,630	1,148	1,256	-	-	-	5,035
7	7884	Cerritos Channel Transmission Line Relocation Project	Jul 2022	15,226	25,788	22,727	11,660	17,525	-	92,926
8	8104	Moorpark-Pardee 220 kV No. 4 Circuit	Dec 2020	3	2,281	521	839	-	-	3,643
9	8077	Annual Transmission Reliability Assessment Protection Upgrades	Mar 2021	-	-	3,282	-	-	-	3,282
10			<i>Subtotal</i>	<i>181,187</i>	<i>79,739</i>	<i>49,509</i>	<i>26,051</i>	<i>24,529</i>	<i>19,731</i>	<i>380,746</i>
11		Projects with CPUC-jurisdictional cost < \$3 M		2,069	1,194	748	-	-	-	4,011
12		Projects In-Service prior to 2019		91,868	1,030	-	-	-	-	92,898
13			Total	275,123	81,963	50,257	26,051	24,529	19,731	477,655

¹⁰⁸ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 226 - 233 – Transmission Projects Descriptions.

¹⁰⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 234 – 267 – Grid Reliability Projects.

¹¹⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 268 – 269 – Grid Reliability Projects In-Service Prior to 2019.

¹¹¹ The Eldorado-Lugo-Mohave Series Capacitor Project is considered a Renewable Transmission Project; however, its associated capital expenditures are internally accounted for under Grid Reliability (CWBS Elements CET-ET-TP-RL).

1 a) **Project Description and Need for Activity**

2 Grid Reliability Projects are planned on the portion of SCE’s system under
3 CAISO’s operational control.¹¹² They are developed as part of CAISO’s Transmission Planning Process
4 (TPP)¹¹³ and are required to support reliability and compliance with NERC,¹¹⁴ WECC,¹¹⁵ and CAISO¹¹⁶
5 system performance standards and criteria. In addition, SCE has its own transmission planning criteria
6 comprised of internal technical design and planning practices. The costs and scope of Grid Reliability
7 Projects are largely under FERC jurisdiction, but may contain certain CPUC-jurisdictional components
8 in scope.

9 In coordination with CAISO’s TPP, SCE performs an Annual Transmission
10 Reliability Assessment (ATRA) for its portion of the CAISO-controlled grid. This assessment is
11 designed to:

- 12 • Evaluate the performance of the SCE transmission system under peak and off-
13 peak conditions for near-term and long-term planning horizons;¹¹⁷
- 14 • Determine transmission constraints under stressed system conditions;¹¹⁸
- 15 • Identify upgrades needed to maintain the reliability of the transmission system
16 and comply with NERC Reliability Standards, WECC Regional Business

¹¹² California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 25 (available at: <http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf> as of August 14, 2019).

¹¹³ *Id.* As described in Section 24 of the CAISO Tariff, this process identifies projects needed for reliability, projects needed to interconnect large generation, projects needed to meet policy goals, and projects driven by economics.

¹¹⁴ NERC TPL-001-4 (available at https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission%20System%20Planning%20Performance%20Requirements&jurisdiction=United%20States as of August 14, 2019).

¹¹⁵ TPL-001-WECC-RBP-2 (available at <https://www.wecc.biz/Reliability/TPL-001-WECC-RBP-2.1.pdf> as of August 14, 2019).

¹¹⁶ California ISO Planning Standards effective September 6, 2018 (available at <http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf> as of August 14, 2019).

¹¹⁷ For planning horizons, “near-term” refers to one- to five-years-out while “long-term” refers to six- to ten-years-out.

¹¹⁸ “Stressed system conditions” refers to instances involving the electric grid when there is maximum transmission line loading.

1 Practice, CAISO Planning Standards, and SCE’s transmission planning
2 criteria.

3 SCE’s ATRA is performed in parallel with the CAISO TPP under the CAISO’s
4 FERC jurisdictional tariff.¹¹⁹ SCE’s Grid Reliability Projects are identified in the CAISO TPP and
5 subject to review and approval by the CAISO Board of Directors and cost recovery based upon the
6 CAISO Transmission Access Charge (TAC).¹²⁰

7 **b) Cerritos Channel Transmission Line Relocation**

8 In the 2018 GRC Decision, cost recovery for the Cerritos Channel Project was
9 disallowed due to its late operating date and concerns that it would not be used and useful in the rate
10 case period.¹²¹ The delayed completion and forecast increase are largely driven by the complexity of the
11 project and higher than anticipated bids for removal of existing underwater foundations inside the
12 channel. Another major contributor to the forecast increase is poor soil conditions resulting in the need
13 for new foundations that are larger than anticipated.

14 **2. Renewable Transmission Projects**

15 The two tables below, Table III-26 (Total Company) and Table III-27 (CPUC-
16 jurisdictional only), list the Renewable Transmission Projects that have over \$3 million in CPUC-
17 jurisdictional capital expenditures and are expected to be completed and operational by the end of 2023.
18 Details regarding forecast expenditures of Renewable Transmission Projects with CPUC-jurisdictional
19 costs of less than \$3 million each are provided in workpapers.¹²²

¹¹⁹ California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 25 (available at: <http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf> as of August 14, 2019).

¹²⁰ *Id.* The CAISO TAC is a two-part rate structure utilized to recover transmission revenue requirements. For more information, see Section 26 of CAISO Tariff.

¹²¹ See D.19-05-020 pp. 63-64.

¹²² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 270 – 271 – Renewable Transmission Projects Less Than \$3M CPUC-jurisdictional Costs.

Table III-26
Renewable Transmission Projects Capital Expenditure Summary^{123,124,125}
CWBS Element CET-ET-TP-RN
(Total Company – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	6420	West of Devers (WOD) Upgrade Project	Dec 2021	241,162	180,022	155,533	122,303	141,275	-	840,296
2	6902	Calcite 220kV Substation	Jul 2021	3,826	300	18,365	19,633	18,690	-	60,813
3	7763	Lugo-Victorville 500 kV SPS	Dec 2020	9,446	364	8,976	2,402	-	-	21,188
4			<i>Subtotal</i>	<i>254,434</i>	<i>180,686</i>	<i>182,874</i>	<i>144,337</i>	<i>159,965</i>	<i>-</i>	<i>922,297</i>
5		Projects with CPUC-jurisdictional cost < \$3 M		317,745	8,903	21,226	41,051	42,208	-	431,133
6		Projects with operating date outside of GRC window		1,709,803	1,004	-	-	-	-	1,710,808
7			Total	2,281,982	190,594	204,100	185,388	202,174	-	3,064,238

Table III-27
Renewable Transmission Projects Capital Expenditure Summary
CWBS Element CET-ET-TP-RN
(CPUC-Jurisdictional – Nominal \$000)

Line No.	Project No.	Project Name	Operating Date	Prior	2019	2020	2021	2022	2023	Total
1	6420	West of Devers (WOD) Upgrade Project	Dec 2021	29,382	5,163	700	3,999	6,342	-	45,586
2	6902	Calcite 220kV Substation	Jul 2021	-	-	1,594	407	1,682	-	3,682
3	7763	Lugo-Victorville 500 kV SPS	Dec 2020	2,316	74	2,090	288	-	-	4,768
4			<i>Subtotal</i>	<i>31,697</i>	<i>5,237</i>	<i>4,384</i>	<i>4,694</i>	<i>8,024</i>	<i>-</i>	<i>54,036</i>
5		Projects with CPUC-jurisdictional cost < \$3 M		2,467	528	1,254	749	832	-	5,831
6		Projects with operating date outside of GRC window		425,561	14	-	-	-	-	425,576
7			Total	459,726	5,779	5,638	5,443	8,857	-	485,443

a) Project Description and Need for Activity

SCE’s Renewable Transmission Projects include interconnection projects and policy-driven projects. SCE facilitates the CAISO generator interconnection process by assisting independently-owned power plants, including renewable generation with interconnection to SCE’s CAISO-controlled grid.¹²⁶ SCE performs interconnection studies with CAISO under CAISO’s FERC-

¹²³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 226 - 233 – Transmission Projects Descriptions.

¹²⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 272 – 283 – Renewable Transmission Projects.

¹²⁵ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. III – Book C - pp. 284 – 285 – Renewable Transmission Projects Outside the GRC Window.

¹²⁶ For a detailed description of CAISO’s transmission planning process and requirements, please refer to CAISO’s business practice manual and procedures found on their website: California Independent System Operator Corporation, available at <http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx> as of August 14, 2019.

1 jurisdictional tariff¹²⁷ and NERC Reliability Standards, and identifies interconnection projects specific to
2 each generator enabling them to interconnect without adverse effects on system reliability.

3 Policy-driven projects are identified by CAISO through the TPP¹²⁸ as those
4 enabling the grid to support state and federal directives. This includes California’s renewable portfolio
5 standard (RPS) to source 33 percent of energy sales from renewable resources by 2020 and Senate Bills
6 350¹²⁹ and 100¹³⁰ mandating renewable energy and greenhouse gas (GHG) reduction targets,
7 respectively, over designated periods. Achieving these objectives requires the development and
8 interconnection of renewable generating resources and the construction of new infrastructure to deliver
9 their output to customers.

¹²⁷ California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 25 (available at: <http://www.caiso.com/Documents/ConformedTariff-asof-Apr1-2019.pdf> as of August 14, 2019.) See also, CAISO Generator Interconnection Procedures, Appendix Y, available at: <http://www.caiso.com/Documents/AppendixY-GIPForInterconnectionRequests-asof-Nov27-2018.pdf> as of August 14, 2019.

¹²⁸ For more information on CAISO Policy-Driven assessments, please refer to the CAISO’s transmission planning process and latest CAISO Transmission Plan available at <http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx> http://www.caiso.com/Documents/ISO_BoardApproved-2018-2019_Transmission_Plan.pdf as of August 14, 2019.

¹²⁹ Senate Bill No. 350 available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350 as of August 14, 2019.

¹³⁰ Senate Bill No. 100 available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100 as of August 14, 2019.

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IV.

ENGINEERING

A. Overview

The Engineering Business Plan Element (BPE) includes SCE’s Transmission and Distribution Grid Engineering costs that are required to ensure our grid is reliable, capable of providing adequate power and allows for interconnection of new generation sources to accommodate load growth and meet California’s RPS requirements. The Engineering BPE also includes the investigative and engineering work to address customer-reported concerns with power quality. The categorization of SCE’s O&M within this Part of the System Augmentation Volume includes:

- Engineering BPE
 - Grid Engineering GRC Activity
 - Load Side Support GRC Activity

The Grid Engineering¹³¹ GRC Activity includes identifying necessary system modifications and expansions on our transmission grid to: a) help ensure compliance with the North American Electric Reliability Council (NERC) and Western Electric Coordinating Council (WECC) Reliability Standards & Criteria; b) participate in local, regional and state activities that involve the planning of new generation, transmission lines and substations; and c) develop detailed engineering designs for system upgrades, modifications, and additions to support the construction, maintenance, and operations of its electrical facilities. As for the remaining portion of the Engineering BPE, if SCE learns through its customers that a service issue has developed, SCE’s Load Side Support Business Plan Activity captures the investigation of the concern and the solution development.

B. 2018 Decision

1. Comparison of Authorized 2018 to Recorded

The 2018 GRC Decision requires SCE to compare the 2018 authorized amounts to the recorded amounts.¹³² In SCE’s 2018 GRC Application,¹³³ SCE’s System Planning O&M expense

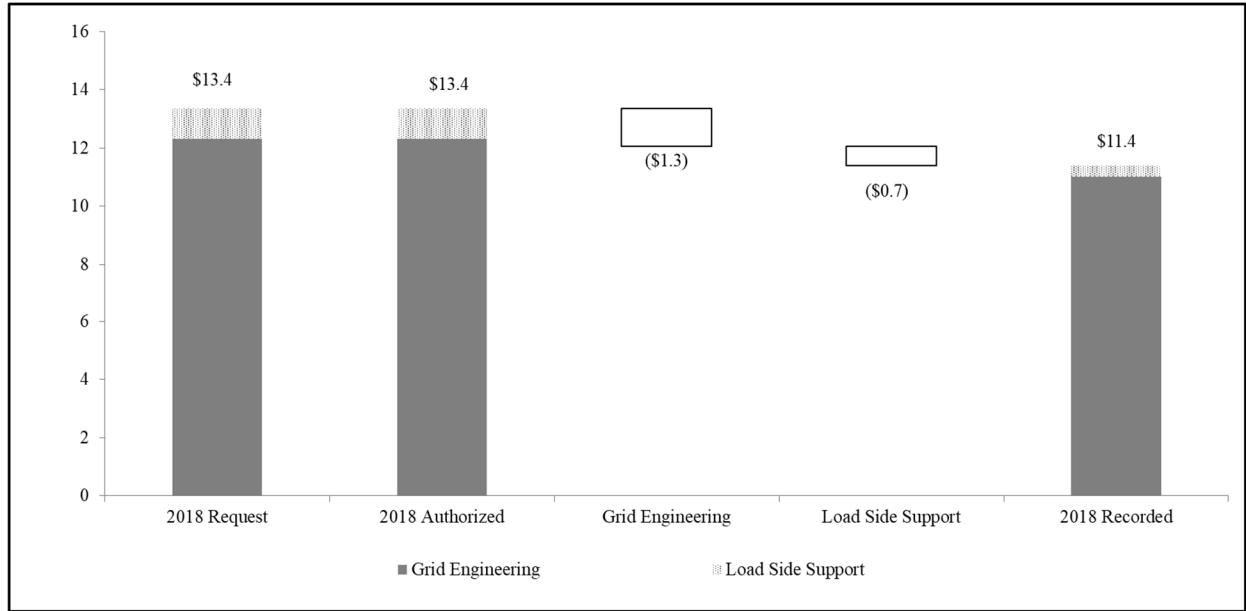
¹³¹ Whereas SCE requested funds for these activities in two distinct categories (Grid Engineering O&M and Transmission & Interconnection Planning O&M) in its 2018 GRC, in this GRC, SCE requests these funds collectively within this Grid Engineering Business Plan Activity.

¹³² D.19-05-020, Ordering Paragraph 22, pp. 441-442.

¹³³ SCE-02, Vol. 03 R, 2018 General Rate Case, Transmission & Distribution, Volume 3 R – System Planning, September 27, 2016.

1 forecasts included the work for Transmission Interconnection and Planning, Grid Engineering, and Load
 2 Side Support. The Commission authorized \$13.4 million in 2018 for these activities. Figure IV-27 below
 3 compares amounts for O&M expenses.

Figure IV-27
2018 GRC Authorized Variance Summary 2018 O&M Expenses¹³⁴
 (Nominal \$Millions)



4 For Grid Engineering, SCE labor expenses were lower than authorized due to several
 5 factors, including (1) organizational realignment activities; (2) employee attrition without adequate
 6 backfill activities; and (3) a shift in Root Cause engineering work being charged to overhead activities,
 7 rather than direct charging to this GRC activity. Non-labor expenses decreased in 2018 as work related
 8 to Distribution Apparatus, Engineering Support, Protection, and Transmission contract services on
 9 several projects was deferred to later years.

10 While the amount of Load Side Support work remained relatively unchanged from prior
 11 years, an accounting discrepancy reduced recorded Labor expenses charged to the 2018 Load Side
 12 Support activity. This is described in more detail in Section IV.C.2.

¹³⁴ Refer to WP SCE-07 Vol. 01 – O&M Authorized to Recorded.

1 **C. O&M Forecast - Engineering**

2 **1. Grid Engineering**

3 **a) Work Description and Need**

4 SCE's engineers and transmission planners perform activities that support the
5 modification and operation of the power system. From long-term planning activities to near-term design
6 and engineering activities, this work supports all voltages of SCE's transmission and distribution
7 systems and the various stages of grid engineering.

8 SCE's transmission system is under operational control of the CAISO, and SCE's
9 distribution grid is under the operational control of SCE. The details of each planning and engineering
10 process are captured in other chapters of this volume. Chapter III - Transmission Projects describes the
11 work related to the CAISO-controlled portions of SCE's grid and Section II.C of the Load Growth
12 chapter highlights the planning process for the system under SCE's operational control (distribution and
13 subtransmission systems).

14 SCE's transmission system performance and configuration are routinely evaluated
15 against mandatory NERC Reliability Standards,¹³⁵ WECC Reliability Standards/Criteria,¹³⁶ and the
16 CAISO Planning Criteria.¹³⁷ Necessary modifications and system expansions must be identified and
17 planned to help ensure compliance with these standards and criteria. System modifications include
18 adding new substations, expanding existing facilities, upgrading equipment, installing voltage support
19 equipment, adding new transmission lines, adding capacity to existing lines, and reconfiguring the
20 system.

21 As part of evaluating the future reliability of the SCE transmission system, SCE
22 participates in root cause evaluations of major disturbances on the Western Interconnection¹³⁸ and in
23 developing recommendations to prevent similar system disturbances.

¹³⁵ NERC Reliability Standards available at:

<https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States>
as of August 14 2019.

¹³⁶ WECC Reliability Standards/Criteria available at: <https://www.wecc.org/Standards/Pages/Default.aspx>, as of
August 14 2019.

¹³⁷ CAISO Planning Criteria available at: <http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf>, as of August 14 2019.

¹³⁸ The U.S. Department of Energy describes the Western Interconnection as “[stretching] from Western Canada
South to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains.” Available at:

(Continued)

1 SCE transmission planners participate in developing CAISO, WECC, and NERC
2 Reliability Standards/Criteria. They also participate in local, regional and state activities that involve the
3 planning of new generation, transmission lines and substations. The studies and planning processes
4 managed by this group require an advanced understanding of bulk power flow, engineering standards,
5 and quantitative modeling. This work is conducted by engineers who have expertise in SCE's
6 transmission system and experience in electric system planning and regulatory policy. SCE also uses
7 contract personnel to perform work associated with specialized projects. These activities are O&M
8 expenses that are necessary to support transmission system reliability and safety.

9 In addition to work that supports planning activities, Grid Engineering includes
10 the engineering activities to support the construction, maintenance, and operations of its electrical
11 facilities across all voltages. This includes developing detailed engineering designs for system upgrades,
12 modifications, and additions to the transmission system, subtransmission system, and distribution
13 system. These activities include:

- 14 1. Studying the root cause of equipment failures in the field to identify necessary
15 corrective actions;
- 16 2. Performing engineering studies necessary to support requests for
17 interconnection or non-standard service requests. Engineering interconnection
18 studies involve evaluating the impact of the interconnection on our
19 equipment/facilities. The studies are necessary to determine if existing
20 equipment/facilities are adequate or if SCE must add/upgrade
21 equipment/facilities to accommodate the interconnection;
- 22 3. Assisting and guiding field personnel in properly installing, operating and
23 maintaining substation and distribution equipment and assets;
- 24 4. Performing evaluations on poles/towers on our system so that structures are
25 properly designed to withstand impacts from high wind-ice combinations and
26 unbalanced longitudinal wire loads;

Continued from the previous page

<https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0>.

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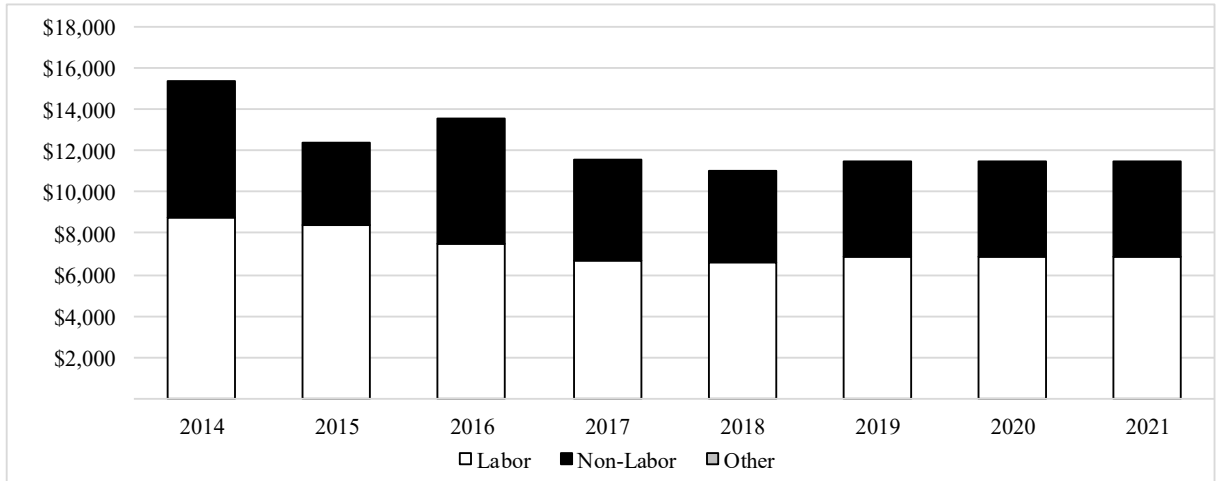
- 5. Performing equipment verification and various engineering studies;
- 6. Evaluating and/or testing equipment developed by vendors for potential widespread use on the SCE system;
- 7. Performing analyses on equipment or devices that may provide safety and/or reliability benefits (e.g. using fuses versus reclosing devices on the distribution network);
- 8. Assessing and designing protective relays, system controls, and automation schemes for SCE’s grid;
- 9. Evaluating and selecting components, software, and systems to enable remote monitoring and operations of transmission and distribution facilities.

b) Scope and Forecast Analysis

The recorded and forecast O&M expenses for Grid Engineering are shown below

in Figure IV-28.

Figure IV-28
Grid Engineering¹³⁹
Recorded 2014-2018/Forecast 2019-2021
(Constant 2018 \$000)



	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
<i>Labor</i>	\$8,748	\$8,379	\$7,529	\$6,675	\$6,600	\$6,880	\$6,880	\$6,880
<i>Non-Labor</i>	\$6,630	\$3,980	\$6,013	\$4,858	\$4,412	\$4,600	\$4,600	\$4,600
<i>Other</i>								
Total Expenses	\$15,378	\$12,359	\$13,542	\$11,533	\$11,012	\$11,480	\$11,480	\$11,480
Ratio of Labor to Total	57%	68%	56%	58%	60%	60%	60%	60%

(1) Historical Variance Analysis

(a) Labor

Labor expenses include the costs for SCE personnel to perform or support the activities described above. As shown in Figure IV-28, labor costs have decreased year-over-year from 2014-2018. These decreases resulted from several factors, including (1) organizational realignment activities; (2) employee attrition without adequate backfill activities; and (3) a shift in Root Cause engineering work being charged to overhead activities, rather than direct charging to this GRC activity. While labor resources were reduced, aggregate workload remained stable or increased. Recognizing this paradigm is not sustainable, especially as forecast workload in this area is anticipated to increase significantly, SCE must right-size labor resources that perform the engineering and planning functions housed in this GRC activity.

¹³⁹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C - pp. 286 - 292 – O&M Detail for Grid Engineering.

1 capitalized work including property reviews and support for regulatory activities at the CPUC and
2 FERC, and increased resources devoted to root cause investigations, including for wildfire event
3 equipment investigations.¹⁴²

4 As California implements the tenets of Senate Bill 100 and Senate
5 Bill 350, which require a shift to a carbon-neutral resource portfolio, SCE expects that the volume
6 and/or complexity of generation interconnection requests, gas plant retirements, and studies to identify
7 upgrades to expand grid infrastructure will increase each year. SCE's requested O&M forecast reflects a
8 reasonable increase in resources commensurate with this growth to accommodate the complexities in
9 planning for and engineering the electric system to enable the achievement of California's policy
10 objectives.

11 **(b) Non-Labor**

12 Similar to labor costs discussed above, non-labor costs have
13 decreased over the three-year period from 2016-2018. Accordingly, SCE forecasts 2021 Test Year non-
14 labor expense by using 2018 recorded expense as a base. This is consistent with Commission guidance
15 which states if recorded expenses have shown a trend in a certain direction over three or more years, the
16 last recorded year is an appropriate base estimate.¹⁴³ To this base, SCE adds incremental expense of \$0.2
17 million to cover the costs of necessary activities required to be performed in the Test Year. These
18 incremental costs generally support the activities discussed in section 1.b)(2)(a) above, and more
19 specifically support additional engineering assessments and studies on various wildfire-related activities,
20 Transmission-level projects, and Protection and Distribution Apparatus projects.¹⁴⁴

21 **2. Load Side Support**

22 **a) Work Description and Need**

23 Load Side Support is an SCE program that addresses issues that can arise as a
24 result of the generation, transmission and delivery of power to our customers. This program provides
25 investigative services that extend beyond the revenue meter and include wiring and grounding

¹⁴² Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C - pp. 293 - 295 - Incremental Grid Engineering Forecast Details.

¹⁴³ In D.89-12-057, and subsequently in D.04.07-022, the CPUC stated that if recorded expenses have shown a trend in a certain direction over three or more years, the last recorded year is an appropriate base estimate.

¹⁴⁴ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C - pp. 293 – 295 Incremental Grid Engineering Forecast Details.

1 inspections, power quality monitoring, and radio frequency interference measurements. SCE's Power
2 Quality department personnel identify the cause of power quality and interference problems and may
3 recommend solutions to customers and/or system owners.

4 The proliferation of microprocessor controllers within DERs, EVs, protective
5 relays, appliances and manufacturing equipment has increased the level of sensitivity customers have to
6 momentary power system disturbances.¹⁴⁵ Power system faults, capacitor switching, and starting of large
7 loads are common sources of disturbances that are addressed by this program. Electronic-based
8 generation and motor control systems have also led to an increase in distortion of the 60-Hertz
9 sinusoidal voltage supplied by the power system.¹⁴⁶ This steady-state phenomenon is referred to as
10 harmonic distortion and results in overheating of motors and transformers, mis-operation of
11 microprocessor controllers, and nuisance tripping of loads such as EV chargers and uninterruptible
12 power supplies.

13 Electromagnetic interference can disrupt the reception and transmission of
14 devices that include radios, wireless networks, audio equipment, computers, and televisions.
15 Affected systems include emergency communication operations (911, police, fire), control systems,
16 utility SCADA systems, and amateur radio. Tracking across soiled or damaged insulators and loose line
17 hardware are sources of interference from the transmission and distribution system. Customer wiring
18 systems and equipment may also generate interference due to devices such as failing doorbell
19 transformers and lighting ballasts.

20 Power Quality Advisors ensure the quality of power delivered to SCE's customers
21 remains within industry recommended limits.^{147,148} Corrective actions may include changes to the
22 customer systems, SCE systems, or both. Recommendations provided to customers to reduce sensitivity
23 to disturbances often include low-cost mitigation equipment and settings changes. Customers operating
24 loads that interfere with the service provided to other customers may be required to install filters or
25 equipment designed to minimize starting currents.

¹⁴⁵ IEEE 1250-2018, IEEE Guide for Identifying and Improving Voltage Quality in Power Systems.

¹⁴⁶ IEEE 519-2014, IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems.

¹⁴⁷ ANSI C84.1-2016, Electric Power Systems and Equipment — Voltage Ratings (60 Hertz).

¹⁴⁸ IEEE 1453-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

1 Power Quality Advisors also investigate causes of stray voltage reported by
2 customers or other utilities. Stray voltage results from the normal delivery or use of electricity that may
3 be present between two conductive surfaces that can be simultaneously contacted by members of the
4 general public or animals.¹⁴⁹ Stray voltage is not related to electrical faults, but it can be result of electric
5 or magnetic fields near transmission lines or from normal return current. These investigations may
6 include testing of underground cabling and inspection of grounding systems owned by customers.

7 SCE employs contract linemen to respond to customer complaints of radio
8 interference, television interference, or similar issues. They perform investigations that reveal the nature
9 of the interference and its cause. These employees recommend solutions to customers and, when needed,
10 work with other SCE field personnel to perform corrective actions to comply with FCC regulations.
11 Corrective actions on the SCE system may include washing or replacing insulators and tightening line
12 hardware.

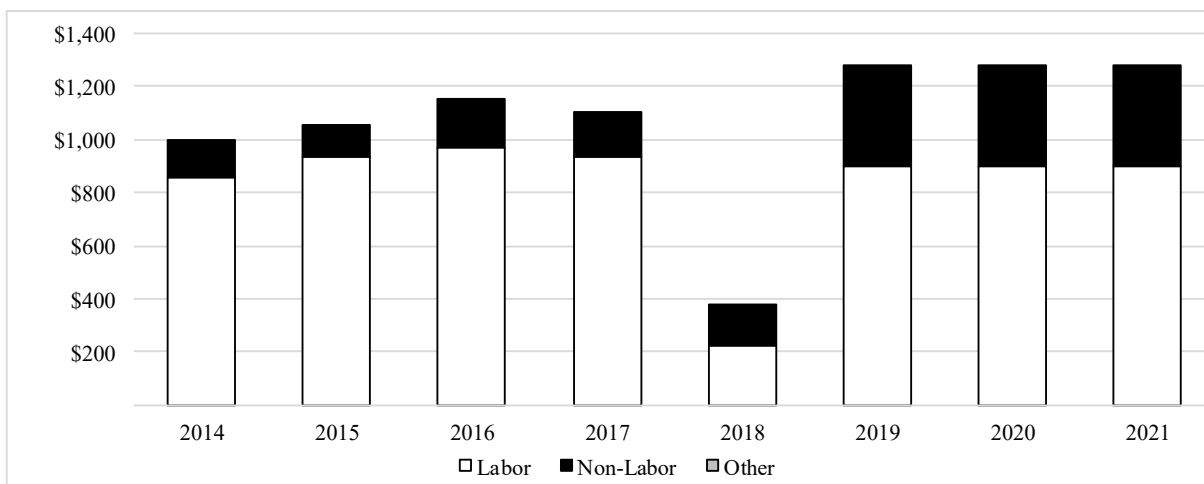
13 Independent consulting services may be utilized in the resolution of complex
14 issues involving DERs, DC fast charging, or other emerging technologies. The rapid deployment of
15 inverter-based generation and high demand charging in SCE’s territory requires advanced circuit
16 modeling to analyze the effects of bi-directional current flow in distribution systems.

¹⁴⁹ IEEE 1695-2016, IEEE Guide to Understanding, Diagnosing, and Mitigating Stray and Contact Voltage.

1 **b) Scope and Forecast Analysis**

2 The recorded and forecast O&M expenses for Load Side Support are shown
 3 below in Figure IV-29.

Figure IV-29
Load Side Support¹⁵⁰
Recorded 2014-2018/Forecast 2019-2021
(Constant 2018 \$000)



	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Labor	\$855	\$936	\$968	\$934	\$224	\$900	\$900	\$900
Non-Labor	\$147	\$121	\$186	\$170	\$159	\$377	\$377	\$377
Other								
Total Expenses	\$1,001	\$1,057	\$1,154	\$1,103	\$383	\$1,277	\$1,277	\$1,277
Ratio of Labor to Total	85%	89%	84%	85%	58%	71%	70%	71%

4 **(1) Historical Variance Analysis**

5 **(a) Labor**

6 While the amount of work remained relatively unchanged from
 7 prior years, an accounting discrepancy reduced recorded Labor expenses charged to the 2018 Load Side
 8 Support activity from the actual \$799,000.¹⁵¹ SCE analyzed timesheet entries to calculate the additional
 9 Labor that should have recorded to Load Side Support over the \$224,000 that correctly recorded to Load

¹⁵⁰ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C – pp. 296 – 302 – O&M Detail for Load Side Support.

¹⁵¹ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C – pp. 303 – 304 – Load Side Support Corrected Forecast Details.

Side Support in 2018. Table IV-28 includes the corrected 2018 Labor amount for reference in this testimony.

Table IV-28
Load Side Support, with 2018 Labor Corrections
Recorded 2014-2017/Corrected 2018/Forecast 2019-2021
(Constant 2018 \$000)

	Recorded					Forecast		
	2014	2015	2016	2017	2018	2019	2020	2021
Labor	\$855	\$936	\$968	\$934	\$799	\$900	\$900	\$900
Non-Labor	\$147	\$121	\$186	\$170	\$159	\$377	\$377	\$377
Total	\$1,001	\$1,057	\$1,154	\$1,103	\$958	\$1,277	\$1,277	\$1,277
Ratio of Labor to Total	85%	89%	84%	85%	83%	71%	70%	71%

Basis of Forecast: Labor: Three Year Average, Non-Labor: Last Year Recorded plus increased contract work
Basis of Labor/Non-Labor Split: Calculated based on forecast

The decrease in 2018 for the corrected labor dollars from previous years is the result of a transition of Radio & TV Interference (RTVI) Inspectors from SCE employees to contractors. Contractor charges fall under non-labor expenses for Load Side Support; therefore there was a decrease in overall Labor charges and an increase in Non-Labor charges for 2019 and beyond. In 2018, the RTVI Inspector transition occurred throughout the 2018 calendar year. Most SCE employees had transitioned out of the program by March 2018, while contractors transitioned into the work by July 2018. The final SCE employee assigned to radio frequency interference investigations was transitioned off by November 2018. SCE used contractors to perform investigations for the remainder of the year.

(b) Non-Labor

Unlike Labor, the 2018 recorded costs of \$158k non-labor O&M shown in Figure IV-29 is accurate. The need for contractors to supplement work or specialized skills required varies year-to-year based on the volume and type of customer calls related to power quality concerns.

(2) Forecast

SCE’s labor forecast for the 2021 Test Year is \$900,000. This is based on a 3-year average of labor costs over the period of 2016 to 2018, using the corrected 2018 record amount for labor. An average is appropriate to use when the recorded amounts are “influenced by weather or

1 other external forces beyond the control of the utility.”¹⁵² Power Quality concerns are driven by third-
2 party activities and can vary year over year. With respect to the observable downward labor trend in the
3 last three years and the labor variances previously described for 2018, SCE contends that Load Side
4 Support is best approximated using a three-year average of recorded costs. SCE expects to experience a
5 similar average workload in the Test Year.

6 The non-labor forecast for this activity is based on 2018 recorded
7 amounts, plus additional costs to support specialized investigations and contract work to address
8 customer needs.¹⁵³ The use of the last recorded year as the basis for the Test Year request is also
9 consistent with the Commission’s guidance on forecasting methodologies. As mentioned earlier, non-
10 labor work is expected to increase due to specialized investigation work performed by a third party firm
11 and contract employees for specialized engineering based on customer needs. This level of funding will
12 enable SCE to adequately respond to and resolve customer issues.

13 The forecast for this incremental external support is based on the
14 increasing complexity of interference and power quality issues that must be addressed by the Power
15 Quality department. Investigations are primarily in response to customer or system issues, therefore the
16 need for these external expert services can vary from year to year.

¹⁵² D.89-12-057.

¹⁵³ Refer to WP SCE-02 Vol. 04 Pt. 2, Ch. IV – Book C - pp. 303 - 304 – Load Side Support Corrected Forecast Details.

Appendix A
Project Alternatives

APPENDIX A
PROJECT ALTERNATIVES

Table 1 and Table 2 include information about the alternative projects that SCE considered for the Substation Expansion projects described in Section II.D.1.c). Table 3 and Table 4 represent alternative projects discussed in the Subtransmission Lines Plan (Section II.D.3.a)) and A-Bank Plan (Section II.D.3.b)).

Table 1
Substation Expansion Project Alternative Details 1 - 8
(Total Company Nominal \$000)

Line No.	Substation	Project No.	Project Scope	Total Cost	Alternative Project Scope	Alternative Cost	Reason Not Selected
1	Sullivan 66/12	7796	Install 1-28 MVA transformer	\$3,421	Brookhurst 66/12 Install 1-28 MVA transformer Upgrade 12 kV switchrack Install 1 new 12 kV circuit	\$5,737	Not the cost effective option
2	Sawville 66/16	8079	Remove 2-11.2 MVA transformers Install 2-28 MVA transformers Install 1-16 kV circuit	\$4,442	Purple 66/16 kV Substation Construct new 66/16 kV customer substation Install 2- 14 MVA transformers Install 1- 16 kV circuit	Customer owned and funded	Customer chose to not continue with the customer substation Space limited, no room for new substation
3	Falcon Ridge 66/12	5397	Construct new 66/12 substation Install 2-28 MVA transformers Install 4-12 kV circuits	\$72,078	Construct new 115/12 Substation Install 2-28 MVA transformers Install 4- 12 kV circuits	\$112,522	Not the cost effective solution Requires longer subtransmission lines to serve new substation
4	Goshen 66/12	7736	Remove 2-14 MVA transformers Remove 1-15.5 MVA transformer Install 2-28 MVA transformers Install 1-12 kV circuit	\$6,882	Install 2-12 kV circuits, 10 miles long each	\$11,200	Not the cost effective solution Timeline does not meet area need
5	Rosamond 66/12	8007	Remove 1-10 MVA transformer Install 1-14 MVA transformer Rebuild 12 kV switchrack Install 1-12 kV circuit	\$4,440	Great Lakes 66/12 kV Substation Rebuild Great Lakes 66/12 kV substation Install 1-28 MVA transformer Install 1 new 12 kV circuit	\$14,865	Not the cost effective option
6	Garnet 115/33	8125	Install 1-56 MVA transformer Install 2-33kV circuits	\$4,173	Blue Dream Substation Construct new 115/33 kV substation Install 4- 56 MVA transformers Install 4 new 33 kV circuits	\$99,469	Not the cost effective solution Timeline does not meet area need Does not address aging infrastructure at Garnet Substation
7	Safari 33/12	7516	Construct new 33/12 substation Install 2-28 MVA transformers Install 3-12 kV circuits Construct new 66/33 substation Install 2-56 MVA transformers Install 2-33 kV circuits	\$45,470	Construct new 66/12 kV substation Install 2-28 MVA transformers Install 4-12 kV circuits Install 2-12 kV circuits at neighboring substations to serve load while licensing activities conclude	\$69,301	Not the cost effective solution Timeline does not meet area need
8	Devers 115/33	8126	Install 2-56 MVA transformer Install 33 kV switchrack Install 2-33 kV circuits	\$12,162	Blue Dream Substation Construct new 115/33 kV substation Install 4-56 MVA transformers Install 4 new 33 kV circuits	\$99,469	Not the cost effective solution Timeline does not meet area need Does not address aging infrastructure at Garnet Substation

Table 2
Substation Expansion Project Alternative Details 9 - 14
(Total Company Nominal \$000)

Line No.	Substation	Project No.	Project Scope	Total Cost	Alternative Project Scope	Alternative Cost	Reason Not Selected
9	Edwards 115/33	8146	Remove 1-25 MVA transformer Remove 1-25 MVA transformer bank Install 1-28 MVA transformer Install 1-56 MVA transformer Rebuild 115 kV switchrack Rebuild 33 kV switchrack Install 1-33 kV circuit	\$7,072	Install new 30 mile 115 kV subtransmission line connected to Calcity substation	\$53,459	Not the cost effective solution Timeline does not meet area need
10	San Antonio 66/12	5174	Remove 2-22.4 MVA transformers Install 2-28 MVA transformers Install 2-12 kV circuits	\$3,455	Construct new 66/12 kV substation Install 2-28 MVA 66/12 kV transformers Install 4 new 12 kV circuits	\$66,000	Not the cost effective solution Timeline does not meet area need
11	Lancaster 66/12	8101	Remove 2-22.4 MVA transformers Install 2-28 MVA transformers Install 1-12 kV circuits	\$11,385	Oasis 66/12 Install 2 12 kV circuits, 7 miles long each	\$13,908	Not the cost effective solution
12	Del Sur 66/12	8102	Install 3- 12 kV circuits	\$5,664	No feasible alternative for this project. The proposed project is the only viable technical solution due to the geographic isolation of the project needs area.	N/A	No other existing infrastructure in the project needs area.
13	Signal Hill 66/12	8143	Remove 2-14 MVA transformers Install 2-28 MVA transformers	\$3,125	Remove Signal Hill 12/4:16 kV Substation Cutover 3- 4 kV circuits to 12 kV circuitry	\$12,214	Not the cost effective solution
14	Garnet 115/33	8043	Install 1-56 MVA transformer Relocate 3 - 56 MVA transformers Rebuild 115 kV switchrack Rebuild 33 kV switchrack	\$75,263	Blue Dream Substation Construct new 115/33 kV substation Install 4-56 MVA transformers Install 4 new 33 kV circuits	\$99,469	Not the cost effective solution Timeline does not meet area need Does not address aging infrastructure at Garnet Substation

Table 3
A-Bank and Subtransmission Lines Plan Project Alternative Details 1-9
(Total Company Nominal \$000)

Line No.	Project Type	Project ID Number	Project Name	Project Scope	Proposed Project Cost	Alternative Project Scope	Alternative Cost	Reason Not Selected
1	New Line	6030	Valley-Hygen 115 kV	Construct a new Valley-Hygen 115 kV Subtransmission Line Project with 25.9 miles of 954 SAC and 300 feet of 1750 AL.	\$112,634,047	GRC ALTERNATIVE - Transfer Hygen Sub to Minn Loma 66 kV System	\$108,757,240	Alternative cost greater than proposed project cost. Proposed project is technically superior to alternative.
2	New Line	6871	Rector-Reerway No. 2 66 kV	Construct a new 66 kV subtransmission line 8.5 miles of 954 SAC and 1 mile of 3000 kcmil AL	\$25,698,966	Rebuild existing rector riverway, rebuild 7.4 miles of 653 acsr to 954 sac, and rebuild 0.232 miles of 2000 cu to 300 cu and Build a new -14 miles 954 SCAR Rector-Oakgrove 66 line	\$39.6 million	More expensive and additional work would be required to expand Oakgrove substation
3	Recable	7505	La Cierregu-Beverly-Cuher 66 kV	Recable 6.1 miles of 1750 AL to 3000 CU on four line segments	\$11,640,786	Install new cables, and conductors to build a 2nd La Cierregu-Beverly 66kV line along the existing route in existing ducts and structures, 5 miles of LG 2000 cu in existing ducts and structures, and 5 miles of 954 OH on existing poles	\$12.2 million	Cost was higher than the proposed project
4	Reconductor	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line	Reconductor 4800 ft (0.9 mi) of 40 CU and 6865 ft (1.3 mi) of 336 ACSR to 954 SAC in the Saugus leg	\$3,087,887	Construct approximately 4 miles of new Saugus - Pichigen 66 kV line with 954 SAC	\$10,739,540	Cost was higher than the proposed project
5	New Line	8003	ElNido-Felton-La Cierregu 66 kV Subtransmission Line	Construct 0.5 mile of 3000 CU and 0.1 mile of 954 SAC into Felton Substation	\$4,905,331	Construct 5 mile circuit with 954 SAC for a new ElNido-Lomox 66 kV Line	\$13,032,364	Cost was higher than the proposed project
6	Reconductor	8252	Saugus-Colosus-Lochheed-Pichigen 66 kV Subtransmission Line	Rebuild 1.82 miles of 40 CU with 954 SAC in the Pichigen leg	\$4,288,805	Construct approximately 4 miles of new Saugus - Pichigen 66 kV line with 954 SAC	\$10,739,540	Cost was higher than the proposed project
7	Reconductor	8151	Irvine 66/12 kV Substation	Upgrade Switchrack, MEER and Replace 66 kV CB Pos. No. 6 (CB# 14) from 1200 A to 2000 A	\$6,713,030	Extend Santiago-Estrella No. 1 66 kV Subtransmission Line to Las Lomas Substation	\$7,398,738	Cost of alternative project does not reflect potential licensing cost associated with the 3.5 mile the extension.
8	Recable	8251	Saugus-Newhall #1 & Saugus-Newhall #2 66 kV Subtransmission Line	Reconductor 4.95 mi of 1750 XLP Underground Cable with 3000 AL	\$20,035,081	Construct a new 6.4 mile line - 5.15 mi overhead and 1.24 mi underground from Saugus - Newhall.	\$24,857,000	Cost was higher than the proposed project and the potential licensing requirement of proposing a new line.
9	New Line	5346	New Valley South Subtransmission Line	Construct 15.4 miles of new 115 kV subtransmission line - 14.8 OH and 0.6 UG G.4 miles reconductor, 2 miles of double circuit, 10 miles new	\$68,138,846	GRC ALTERNATIVE - Valley - Triton 115kV Line. Construct approximately 21.5 miles of 115kV line to create the new Valley-Triton 115kV line.	\$16,530,000	Proposed project utilizes existing lines and positions. Project alternative cost does not reflect potential licensing costs and challenges of 21.5 miles of new 115 kV line in new ROW.

Table 4
A-Bank and Subtransmission Lines Plan Project Details 10 -16
(Total Company Nominal \$000)

Line No.	Project Type	Project ID Number	Project Name	Project Scope	Proposed Project Cost	Alternative Project Scope	Alternative Cost	Reason Not Selected
10	Reconductor	7764	Vestal-Columbine-Delino-Earlimart 66 kV	Reconductor 9.7 miles of 20 BC to 954 SAC	\$3,268,070	ALTERNATIVE to Vestal-Columbine-Delino-Earlimart 66 kV Reconductor (PIN 7764) & Earlimart-Whelan 66 kV Reconductor (PIN 7852). Vestal 220/66 (S) - New 13.7 mile 66 kV Vestal-Earlimart line	\$30,864,310	Alternative Cost significantly greater than Proposed Project Cost
11	Reconductor	8002	El Nido-Lemnox-Polaris-Yukon 66 kV Subtransmission Line	Reconductor the El Nido and Lemnox legs of the El Nido-Lemnox-Polaris-Yukon 66 kV underground portions from 1750 KCMIL AI to 3000 KCMIL Cu. The El Nido underground portion is approximately 0.5 mile and the Lemnox underground portion is approximately 1.5 mile. Replacing the adjacent La Cerega-El Nido 66 kV Subtransmission Line that shares the same duct work. Replace the CO-8 relays at El Nido Substation on the Lemnox-Polaris-Yukon 66 kV Subtransmission Line with SEL-31C	\$6,940,705	Construct 5 mile circuit with 954 SAC for a new El Nido-Lemnox 66 kV Line	\$13,032,364	Cost was higher than the proposed project
12	Loop-In	4891	Arrowhead 115/33 kV Substation	Loop in project and reconfigure 115 kV subtransmission line arrangement.	\$1,859,728	No Alternative is needed for this project < \$3M		
13	A-Bank	5383	Chino 220/66 kV	Install a fourth 280 MVA transformer and split the system. Install two new 28.8 MVAR 66 kV capacitors and rebuild the 66 kV switchrack.	\$53,531,956	Install a new 280 MVA transformer bank at Men Loma 220/66 kV Substation and construct a new 20 mile 66 kV subtransmission line to Firehouse Substation and rebuild the switchrack at Chino Substation	\$88,074,000	Cost was higher than the proposed project
14	A-Bank	7767	Johanna 220/66 kV	Install a new 280 MVA transformer to correct an N-1 Likely Contingency STELL overload. Extend 66 kV switchrack to install new transformer.	\$19,307,158	Install a new 280 MVA transformer bank at Villa Park 220/66 kV Substation and split the 66 kV bus. Extend the 220 kV switchrack one position. Reconfigure 66 kV subtransmission lines. Add ground banks to two A-bank transformers.	\$39,959,000	Not the lower cost option
15	A-Bank	7740	Del Amo 220/66 kV	Del Amo 220/66: Replace (40) 66 kV bus disconnect switches. Replace (2) sectionalizing disconnect switches. Replace (2) sectionalizing CBs. Reconductor 66kV A section bus from 2-1033 KCMIL to 3-2156 KCMIL. Reconductor 66kV C section bus from 2-1033 Kernl	\$3,847,502	Transfer Carmelita 66/12 kV Substation to Center by looping Carmelita to Center-Miraly-Pinney-Tehagan Line. Construct a 3.5 mile new 66 kV line. Reconfigure Carmentia-La Mirada 66 kV Line to form Eric-La Mirada 66 kV Line and Carmentia-Greening Line to Eric-Greening line.	\$8,000,000	Cost was higher than the proposed project
16	Reconductor	7851	Pottersville-Woodville 66 kV	Reconductor 6.6 miles of 20 BC to 954 SAC	\$3,048	Construct approximately 15 miles of new Springville-Woodville 66 kV line with 954 SAC	\$46,233	Not the lower cost option