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SOUTHERN CALIFORNIA EDISON®

(U 338-E)

2025 General Rate Case

Load Growth, Transmission Projects, and Engineering

Before the

Public Utilities Commission of the State of California

Rosemead, California
May 12, 2023

SCE-02 Vol 07: Load Growth, Transmission Projects, and Engineering

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I.

INTRODUCTION

A. Content and Organization of Volume

This volume is Part 2 for the System Augmentation Business Planning Group (BPG), which includes the activities Southern California Edison Company (SCE) performs to make modifications to the electrical system. Part 2 is composed of the following Business Planning Elements (BPEs):

- Load Growth
- Transmission Projects
- Engineering

These BPEs cover the capital expenditures required to support load growth, including transportation electrification-driven load growth, Distributed Energy Resources (DER)-related growth, transmission grid reliability, transmission facilities to support renewable generation, as well as the Engineering O&M that supports these activities.

Due to the differences in design and operation of the transmission, subtransmission, and distribution systems, each system is covered under separate planning processes. The upgrades, modifications, and additions to the distribution and subtransmission systems are captured in the Load Growth Chapter of this volume, while the upgrades, modifications, and additions to the transmission system are covered within the Transmission Projects Chapter. The O&M activities related to Grid Engineering and Load Side Support are discussed in the Engineering Chapter. 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. Collectively, the capital and O&M expenditures necessary to plan for the near- and long-term changes on the system are:

- Load Growth BPE
  - Distribution Substation Plan Projects
  - DER-Driven Grid Reinforcement Program
  - Transmission Substation Plan Projects
  - System Improvement Programs
  - Various Rights of Way (Land Rights Management)
  - Climate Driven Distribution Circuit Tie Projects
  - Transmission Projects BPE
  - Grid Reliability Transmission Projects

- Renewable Transmission Projects
- Generation Interconnection Remedial Action Scheme
- Transmission Economic Projects
- Engineering BPE
- Grid Engineering
- Load Side Support

Each chapter below includes analyses for each BPE of: (1) regulatory and compliance requirements, (2) O&M and capital funding authorized in the 2021 General Rate Case (GRC) compared to recorded amounts in 2021, (3) the 2025 O&M Test Year forecast relative to historical spending, and (4) the 2023 – 2028 capital expenditure forecast.

B. Summary of O&M and Capital Request

SCE's total requests for the System Augmentation BPG Part 2 (Volume 7) of $13.845 million (constant 2022 dollars) in O&M expenses for the 2025 Test Year and $4,905 million in capital expenditures for the years 2023 to 2028 are presented in Figure I-1 and Figure I-2.

Figure I-1
System Augmentation Part 2 2025 O&M Forecast
(Total Company Constant $000)

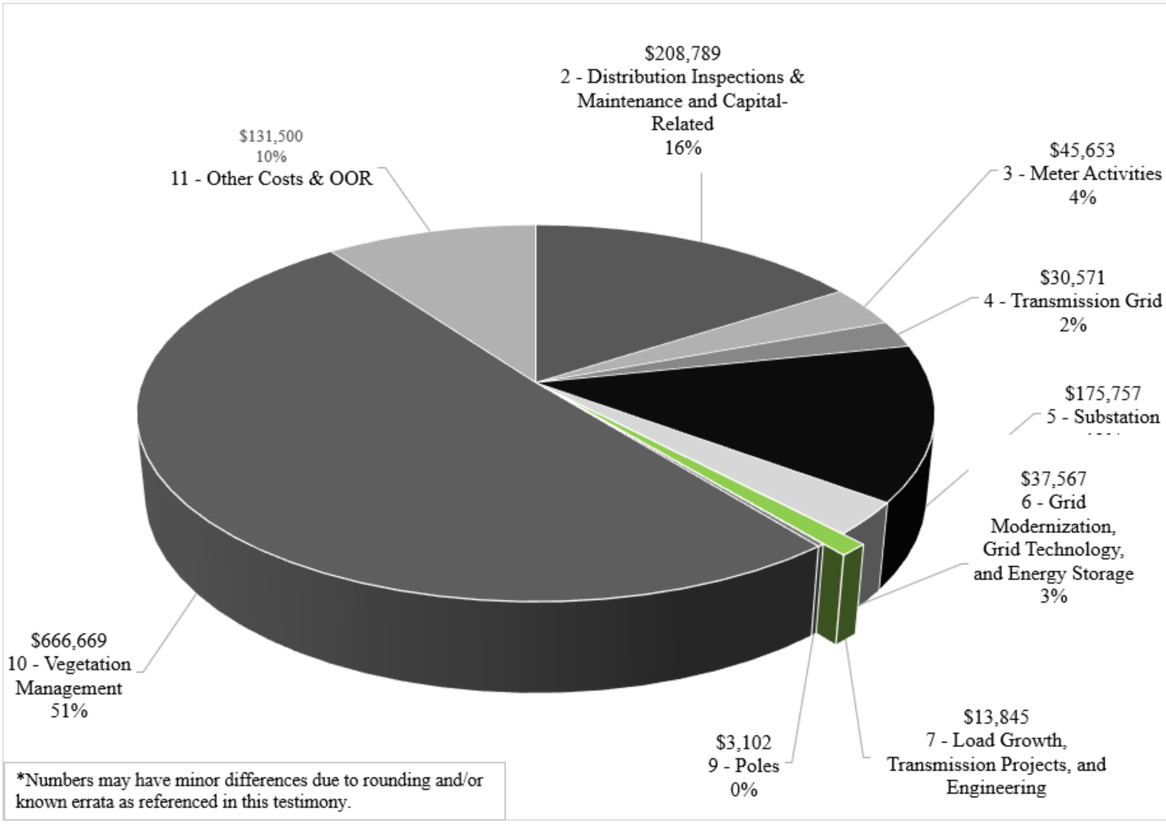
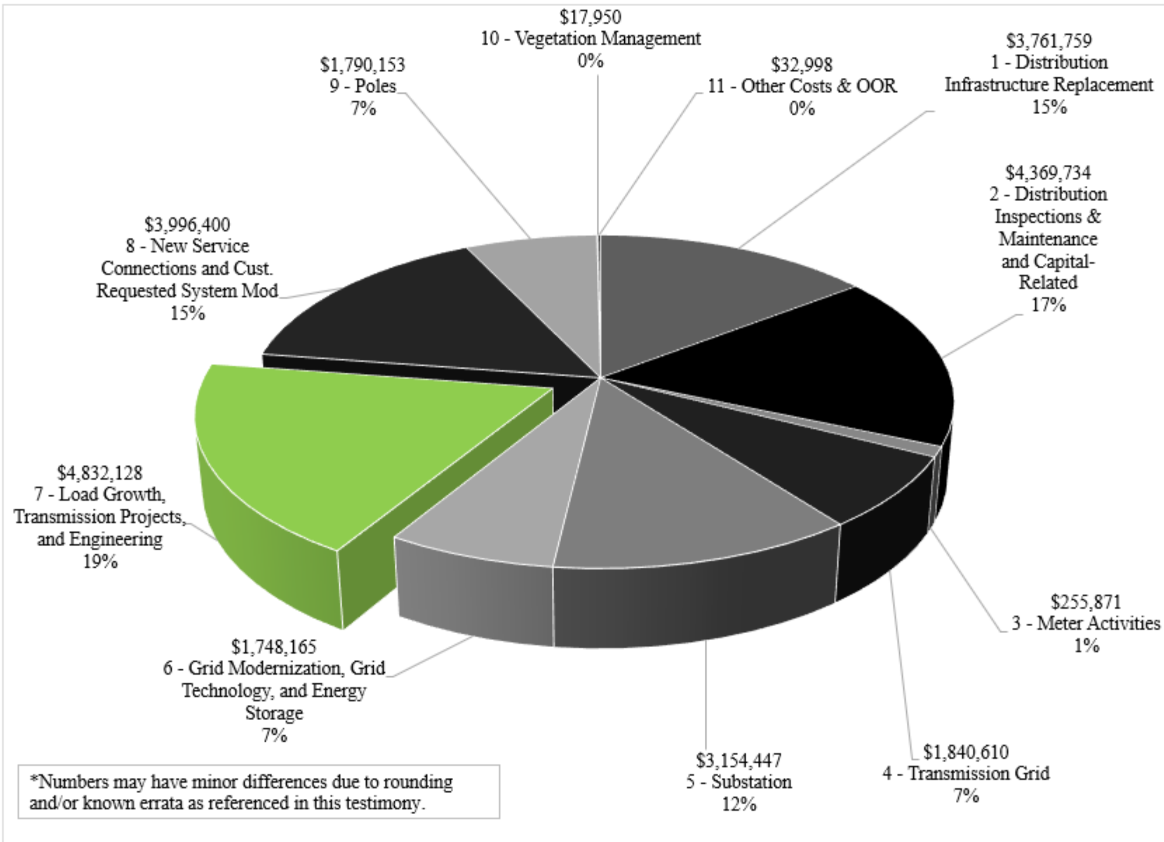


Figure I-2
System Augmentation Part 2 Capital Expenditures 2023-2028
(Total Company Nominal $000)



II.

LOAD GROWTH

A. Overview

SCE's Load Growth Business Plan Element (BPE) covers work needed to support customer load growth, including transportation electrification load and Distributed Energy Resources (DER)[1] growth throughout SCE's electric grid. Due to the differences in design and operation of the electric transmission, subtransmission, and distribution systems, each electric system is planned for using separate planning processes. 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 testimony.

Each year, SCE develops transmission, subtransmission, and distribution system plans that describe the projects and programs required to expand, upgrade, and reconfigure the electric grid over the next 10 years to meet forecasted increases in customer peak demand and interconnection of new generation resources. The following figure provides an "Electric Grid – Power System Overview," which includes infrastructure comprised of transmission lines, subtransmission lines, substations, distribution circuits, and critical equipment such as circuit breakers, relays, substation transformers, conductors, and automation apparatus.

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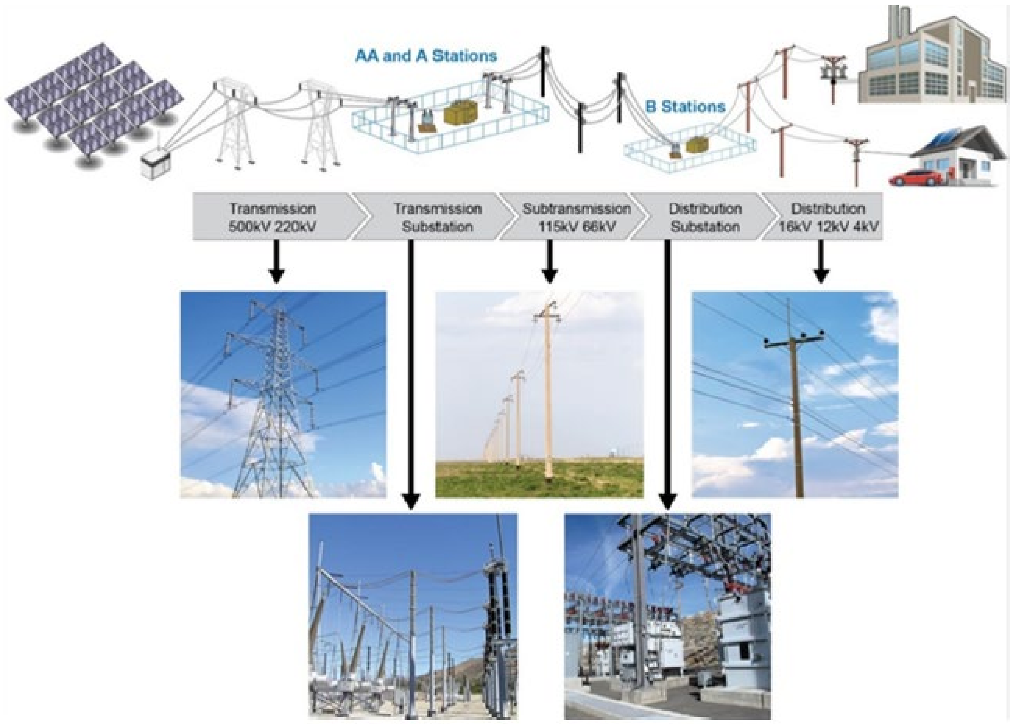
[1] DERs can include energy efficiency, energy storage, demand response, electric vehicles, and distributed generation.

Figure II-3
Electric Grid – Power System Overview



Key drivers for modifications of SCE's electric grid are to safely and reliably accommodate increasing system capacity needs resulting from new customers, as well as increasing load from existing customers. In addition, other drivers such as DER integration, building and transportation electrification State policies, and increasing end-user energy consumption during projected extended heat storms, require additional electric grid reinforcements. SCE considers all these drivers to find the overall least cost and best fit holistic preferred infrastructure solution.

1. Regulatory Background and Policies Driving SCE's Request

As discussed in Mr. Takayesu's Grid Policy testimony, climate change impacts, including decarbonization requirements necessary to meet State and Federal climate goals, are driving one of the most significant shifts in electricity consumption in the past 100 years.[2] Customers will need more electricity for all aspects of their lives, which will in turn drive the fastest load growth in decades (~8%[3]

[2] *See* SCE-02, Vol. 1, Pt. 1, at pp. 1, 4.

[3] Calif. Energy Commission, Integrated Energy Policy Report (SCE 2022 Local Reliability Scenario). *See*. https://efiling.energy.ca.gov/GetDocument.aspx?tn=248356.

growth over this rate case period). The following sections provide a summary of California's Roadmap for Decarbonization, which includes the electrification of the transportation sector and buildings.

a) <u>California's Roadmap for Decarbonization</u>

In December 2022, the California Air Resources Board (CARB) approved the 2022 Scoping Plan for Achieving Carbon Neutrality by 2045 (2022 Scoping Plan), as required by the California Global Warming Solutions Act of 2006 (AB 32) to be developed and updated every five years.[4] The Scoping Plan is the State's roadmap to achieve carbon neutrality by no later than 2045 with a pathway that is cost-effective and technologically feasible to achieve the State's climate targets. The 2022 Scoping Plan expands upon earlier plans with a target of reducing anthropogenic emissions to 85% below 1990 levels by 2045. The 2022 Scoping Plan identifies a path to keep California on track to meet the SB 32 greenhouse gas (GHG) reduction target of at least 40 percent below 1990 emissions by 2030 and identifies a path to achieve carbon neutrality by 2045. The 2022 Scoping Plan includes a target for transportation electrification goals of 100% of light-duty vehicle sales being zero-emission by 2035 and 100% of medium- and heavy-duty (MDHD) sales being zero-emission by 2040.[5] The 2022 Scoping Plan also includes building electrification targets such that there are 3 million all-electric and electric-ready homes by 2030 and 7 million by 2035, contributing to 6 million heat pumps installed statewide by 2030.[6]

b) <u>State and Federal Policies Accelerating Transportation Electrification</u>

As described under the State's Roadmap for Decarbonization, accelerating transportation electrification is a key policy driver for the State. In September 2020, Governor Newsom issued Executive Order (EO) N-79-20 mandating that the sales of all new light-duty vehicles must be zero-emission by year 2035 and sales of new MDHD vehicles must be zero emission by year 2045, where feasible.[7] Subsequently, the CARB approved the Advanced Clean Cars II regulation codifying the

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[4] Calif. Air Resources Board, AB 32 Climate Change Scoping Plan, https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan, accessed April 2023.

[5] Calif. Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality, November 16. 2022, Table 2-1: Actions for the Scoping Plan Scenario: AB 32 GHG Inventory sectors, p. 72, https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf, accessed April 2023.

[6] *Id.* (p. 6).

[7] Governor's Exec. Order N-79-20 (September 23, 2020). Text *available at* https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.

light-duty target in EO N-79-20.[8] In addition, CARB's Advanced Clean Trucks regulation establishes zero emission sales requirements from 2024-2035 for manufacturers of MDHD vehicle class 2b-8 trucks.[9] Finally, CARB's recently adopted Advanced Clean Fleets regulation provides a phased in process starting in 2024 for transitioning drayage trucks, state and local government fleets, and Federal and high-priority fleets to zero emission vehicles.[10] As outlined in CARB's 2020 Mobile Source Strategy (MSS), these policies are necessary to achieve the air and climate goals of the State.[11]

In addition to CARB, several other agencies are pushing the acceleration of transportation electrification. For example, the California Energy Commission's (CEC) Electric Vehicle Charging Infrastructure Assessment pursuant to Assembly Bill (AB) 2127 forecasts that to meet the needs of CARB's MSS, 1.2 million EV chargers will be needed to support an estimated 8 million light-duty EVs, and an additional 157,000 EV chargers will be needed to support the 180,000 MDHD vehicles that are anticipated by year 2030.[12] Tax credits[13] and charging infrastructure funds[14] provided by Federal policy will accelerate this transition to EVs.

As recognized in the CPUC's Final Decision on the Transportation Electrification Framework (D.22-11-040), the distribution system will require grid expansion and upgrades to address this increasing EV load and prepare the grid (e.g., transportation electrification grid readiness).[15] The

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8 Calif. Air Resources Board, Advanced Clean Cars II Regulation, Section 1962.4(a) and (c)(1)(B), effective as of November 30, 2022, Final Regulation Order, *available at* https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii.

9 Calif. Air Resources Board, Advanced Clean Trucks Regulation, Section 1963.1(b), effective as of March 15, 2021. Final Regulation Order is *available at* https://ww2.arb.ca.gov/rulemaking/2019/advancedcleantrucks.

10 Calif. Air Resources Board, Advanced Clean Fleets Regulation was adopted on April 28, 2023, *available at* https://ww2.arb.ca.gov/rulemaking/2022/acf2022.

11 Calif. Air Resources Board, 2020 Mobile Source Strategy, pp. 4-5 (October 28, 2021), *available at* https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

12 Calif. Energy Commission, Electric Vehicle Charging Infrastructure Assessment – AB 2172, p. ii, (July 2021), *available at* https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127.

13 Internal Revenue Service, Credits for New Clean Vehicles Purchased in 2023 or After, *available at* https://www.irs.gov/credits-deductions/credits-for-new-clean-vehicles-purchased-in-2023-or-after.

14 Calif. Energy Commission, National Electric Vehicle Infrastructure Program. This program has allocated funding to the states to create a nationwide interconnected network of DC fast chargers along the National Highway System. California's share will be $384 million over 5 years. Details available at the CEC's website: https://www.energy.ca.gov/programs-and-topics/programs/national-electric-vehicle-infrastructure-program-nevi.

15 D.22-11-040, p. 12.

State and Federal policies will drive the adoption of electric vehicles, which will in turn lead to the need for grid expansion.

To keep pace with the State's roadmap for decarbonization and policy objectives, it is imperative that these policies be reflected within SCE's grid planning forecasts, especially for transportation and building electrification demand. Doing so will enable SCE to timely perform system planning activities that identify and deploy the necessary grid infrastructure to support the State's objectives on a timely basis.

c) State Policies Accelerating Building Electrification

Accelerating building electrification is another key policy driver for the State. In 2021, the CEC's AB 3232 Building Decarbonization Assessment concluded that reducing direct emissions in buildings requires a shift toward electric end uses and that electrification must be a major component of any decarbonization plan.[16] In December 2022, the members of the Board of the CARB approved unanimously the 2022 Scoping Plan.[17]

The 2022 Scoping Plan established a target for Building Electrification such that there will be 3 million all-electric and electric-ready homes by 2030, and 7 million by 2035, contributing to 6 million heat pumps installed statewide by 2030, supported by a requirement for all-electric appliances beginning in 2026 for residential and in 2029 for commercial applications.[18] Additionally, 80% of appliance sales will have to be electric by 2030 for existing residential/commercial and 100% of appliance sales will have to be electric by 2035 for existing residential and by 2045 for existing commercial where appliances are replaced at end-of-life.[19]

As California expeditiously moves towards the achievement of its 2030 decarbonization and 2045 carbon neutrality goals, the CPUC has continued to set important building electrification policies that directly affect customers. In the Building Decarbonization Rulemaking

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[16] Calif. Energy Commission, Final Commission's Report California Building Decarbonization Assessment, p. 10 (Aug. 2021), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311 (hereafter "CEC Building Decarbonization Report").

[17] Calif. Air Resources Board, 2022 CARB Scoping Plan documents (2022), *available at* https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents.

[18] Calif. Air Resources Board, California 2022 Climate Change Scoping Plan, p. 76 (2022), *available at* https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp.pdf.

[19] Calif. Air Resources Board, California 2022 Climate Change Scoping Plan, p. 76 (2022), *available at* https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp.pdf.

(R.19-01-011), the Commission is developing a large-scale approach to decarbonize buildings, which includes development of new initiatives to support a building decarbonization policy yet to be accomplished.[20]

d) Hardened, Resilient, and Flexible Expanded Grid to meet Decarbonization Policies and Physical Climate Impacts

Meeting this higher demand for carbon-free electricity from these regulatory and policy drivers will require more utility scale and distributed generation and storage, alongside increased customer engagement, load management, and demand response tools. In parallel, and most relevant to this Volume of testimony, the grid will need additional capacity and updated assets, configurations, and technology to operate effectively. As electricity use increases so will customers' reliance on consistent availability of electric services, including during emergencies. Projected physical climate change impacts from increased wildfire exposure and flooding to distribution infrastructure will likely also impact availability of electric service. Meeting these needs will require a more hardened, resilient, and flexible expanded electric grid.[21]

2. Compliance Requirements

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

In the 2015 GRC Decision, the Commission directed SCE to "provide clear unit cost forecast information for the major types of equipment...so that the total cost forecast for the project or program can be compared to the sum of the unit costs."[22] Consistent with this requirement, SCE has included the detailed unit cost and number of units required for the major types of equipment in workpapers. Unit costs can vary between projects and programs as shown in the workpapers. The Commission also directed SCE to "provide analysis of the preemptive [circuit breaker] replacements in combination with other types of replacements."[23] In SCE-02, Vol. 05, SCE describes the circuit breaker infrastructure replacement program, which identifies bulk power circuit breakers and distribution circuit breakers approaching the end of their service lives that will need replacement. In that testimony, SCE presents an analysis of these preemptive circuit breaker replacements. When SCE identifies circuit breakers to be replaced under infrastructure replacement, those breakers are itemized by substation. The

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[20] D.23-02-030, p. 4.

[21] *See* SCE-02, Vol. 1, Pt. 1, at pp. 11-12.

[22] D.15-11-021.

[23] D.15-11-021, p. 80.

Substation Equipment Replacement Program (SERP), described in Section II.C.4.e)(4)II.D.4.d) of this volume, upgrades substation circuit breakers projected to exceed short circuit duty interrupting capabilities. Under this program, SCE performs fault duty studies that identify circuit breakers that must be upgraded to interrupt the fault current safely and effectively at a substation. The forecast for this program includes only those breakers not already identified as part of circuit breaker infrastructure replacement in SCE-02, Vol. 05.

b) Distribution Resource Plan Track 3: Policy Issues (D.18-02-004)[24]

SCE's Load Growth capital expenditures in this GRC are influenced by Track 3 of the Distribution Resources Plan (DRP).[25] Track 3 of the DRP is divided into three Sub-tracks, and this Load Growth testimony satisfies compliance requirements within Sub-track 1: Growth Scenarios and Sub-track 3: Distribution Investment Deferral Framework (DIDF).

(1) Sub-track 1: Growth Scenarios

DRP Track 3, Sub-track 1 mandates that the "IEPR demand forecast will be adopted with updated Distributed Energy Resources (DER) forecasts in January 2018," beginning with the "2018-2019 distribution planning cycle."[26] To accomplish this investor-owned utilities (IOUs) were to develop and "vet disaggregation methods though the Growth Scenario Working Group and incorporate best practices in their planning processes"[27] with a subsequent ruling directing forecast disaggregation issues to be vetted in the Distribution Forecasting Working Group (DFWG).[28] Section II.C.2 describes SCE's methodology for adopting the IEPR demand forecast as the load growth forecast at the system level. Additional details on disaggregation methodologies are described in the DFWG Final Report, including the consensus finding that the disaggregation methods employed by SCE are reasonable for disaggregating the IEPR forecasts.[29]

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[24] Sub-track #2 focuses on Grid Modernization investments and are covered in the Grid Modernization Chapter in SCE-02, Vol. 06.

[25] D.18-02-004.

[26] D.18-02-004, Ordering Paragraph No. 1.a., p. 82.

[27] D.18-02-004, Ordering Paragraph No. 1.c., p. 82.

[28] R.14-08-013, Joint Ruling of Commissioner and Administrative Law Judge Establishing Parameters and Schedule for the Distribution Forecasting Working Group (March 29, 2018), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M212/K597/212597901.PDF.

[29] R.14-08-013, Distribution Forecasting Working Group Final Report (June 28, 2018), *available at* https://drpwg.org/growth-scenarios/.

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

The October 21, 2016 Assigned Commissioner's Ruling on Track 3 Issues finalized the scope of Track 3, Sub-track 3 of the DRP to (1) establish a process to identify opportunities for DERs to defer or avoid traditional infrastructure projects, (2) establish a process for utilities to seek authorization and cost recovery for DER sourcing to enable deferral or avoidance of traditional grid infrastructure investments, and (3) consider a process to ensure savings from deferred or avoided distribution investments are accurately reflected in relevant GRC filings.[30] As part of the DIDF, D.18-02-004 orders the IOUs to file two reports on an annual basis that are key components to achieving the Commission's objective to defer traditional infrastructure investments by competitively sourced DERs. The Grid Needs Assessment (GNA) Report summarizes forecasted deficiencies across the distribution system related to capacity, reliability (back-tie), voltage, reactive power, resiliency (microgrid), or a combination of services. The Distribution Deferral Opportunity Report (DDOR) summarizes traditional infrastructure investments that SCE has identified to mitigate the deficiencies in the GNA Report. Section II.C.5 describe SCE's process for providing both the GNA Report and DDOR on an annual basis, along with details on how SCE maximizes asset utilization to achieve the least-cost solution for projects. While D.18-02-004 requires publication of GNA and DDOR reports annually, it recognized that the timing of the annual GNA Report and DDOR publication will be different than the GRC testimony submittal in a GRC year. As such, the decision directs the IOUs to explain differences between the GNA and DDOR publications and GRC testimony within the applicable GRC testimony. Explanation of differences between projects identified in SCE's 2022 DDOR and projects reflected in this GRC testimony are provided in workpapers.

B. 2021 Decision

1. Comparison of Authorized 2021 to Recorded

The 2021 GRC Decision requires SCE to compare the 2021 authorized amounts to the recorded amounts.[31] Figure II-4 below compares amounts for capital expenditures.

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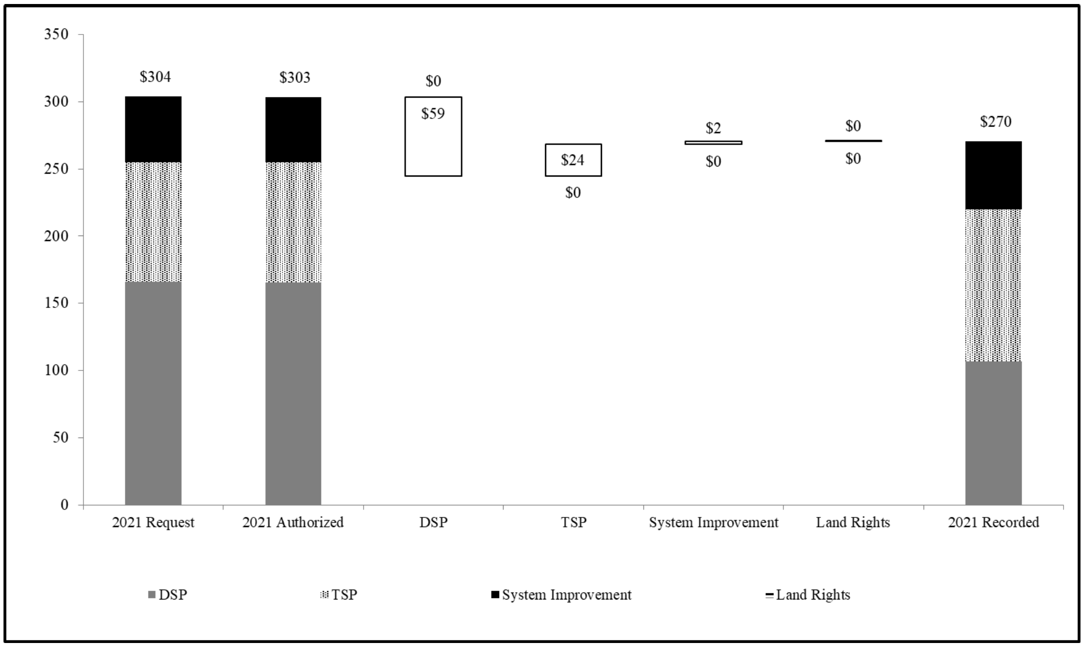
[30] R.14-08-013, Assigned Commissioner's Ruling on Track 3 Issues, (October 21, 2016), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M168/K810/168810330.PDF.

[31] D.21-08-036.

Figure II-4
Load Growth[32]
2021 GRC Authorized Variance Summary 2021 Capital
(Total Company – Nominal)



In 2021, SCE recorded $270 million or 10.9% less than the $303 million authorized for the Load Growth BPE. This 10.9% variance was primarily due to COVID-related impacts and changes to the environmental review process. COVID-related challenges affected multiple areas of the Load Growth BPE, including material cost increases, supply chain delays, availability of crews, and a change in customer operation (work from home versus commercial and industrial operation).

Material cost increases impacted all equipment being procured for construction. For instance, the equipment cost of a common type of overhead distribution transformer was 18% higher in 2021 than it was in 2019. However, this effect was offset by industry supply chain delays due to COVID, which significantly extended cycle times to engineer, procure, and construct equipment. For instance, the ability to construct new circuit projects was delayed due to the availability of distribution transformers.

Meanwhile, construction crews also had challenges with qualified electric worker availability due to health concerns, illnesses, additional safety precautions, and the shift of resources to

32 *See* WP SCE-07, Vol. 01, Authorized vs. Recorded.

wildfire programs which extended timelines to construct. Along with the impact to crew schedules, crews were also rerouted to address emerging immediate needs, such as residential area outages, to support customers working from home rather than being onsite at their traditional work location. Due to more customers working from home, along with increased temperatures over the summer, residential customer usage increased above forecasted values, which meant that crews were responding to unplanned and emergent operations more than expected.

As for the environmental reviews, changes to the General Order (GO) -131D environmental review process caused delays in construction while exemptions were reviewed. Additional changes to local environmental concerns also impacted the ability to construct new circuits. Specifically, a change in flood control strategy in the Rurals planning region caused a redesign of several new circuits.

The following sections summarize the key variance drivers for each of the Load Growth BPE Programs.

a) <u>Distribution Substation Plan (DSP) Variance Drivers</u>

With respect to the DSP, SCE recorded $59 million or 35.5% less than authorized in 2021. This was primarily due to COVID-related impacts including: extended engineering, procurement, and construction cycle times; supply chain challenges; crew safety precaution, scheduling, and illness challenges; and impacts due to the needs to address emergent operational needs resulting from customers working largely from home. Additional factors included local environmental concerns, which impacted the ability to construct new circuits in some cases.

b) <u>Transmission Substation Plan (TSP) Variance Drivers</u>

With respect to TSP, SCE recorded $24 million or 26.4% more than authorized in 2021. While TSP experienced the same COVID and environmental challenges as the rest of the Load Growth BPE activities, this was counteracted by the impact of upgrades for major sporting events and the construction of the SoFi stadium in Inglewood, CA as well as changes to project scope. More specifically, the TSP program incurred additional cost to support increased hotel construction and redundancy for stadium locations that was not part of the prior GRC. The increase in cost was also driven by additional scope change for projects given the difference in the load landscape at the time of completion versus what was identified in initial design from several years ago. For instance, the Rector-Kramer line scope was modified to include additional load drop schemes as the project was nearing completion.

c) **<u>System Improvement Programs Variance Drivers</u>**

With respect to System Improvement Programs, SCE's recorded spending was close to the authorized amount, with the recorded exceeding authorized by 4.3% or $2 million.

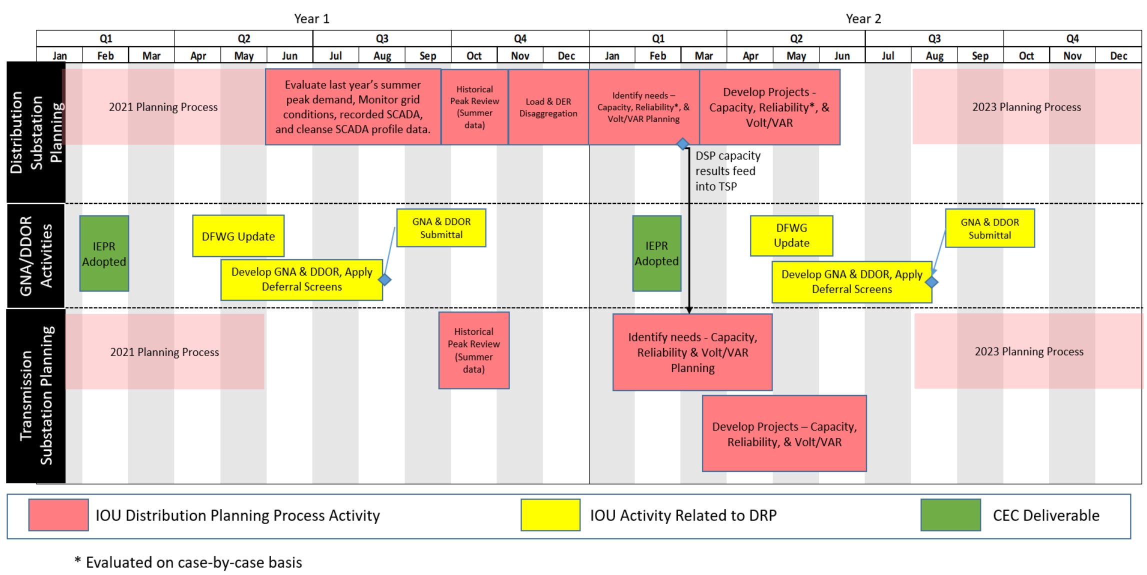
d) **<u>Land Rights Management Variance Drivers</u>**

With respect to Land Rights Management, SCE's recorded spending was close to the authorized amount, with the recorded exceeding authorized by 3.85% or $0.025 million.

C. <u>Distribution & Subtransmission Planning Process</u>

SCE's typical timelines for its Distribution and Subtransmission Planning Process, which includes both distribution system analysis, substation system analysis, and GNA Report and DDOR activities, is depicted in the following figure.

Figure II-5
Distribution and Subtransmission Planning Process System Overview



SCE's Distribution and Subtransmission Planning Process is integrated with the DRP Track 3 requirements and at a high level involves several key activities:

- historical profile reviews to develop starting points
- development and disaggregation of load growth and DER forecasts
- technical planning analyses to identify grid needs
- solution identification and evaluation based on the identified needs
- evaluation of deferral opportunities

These activities are further described in the following sections.

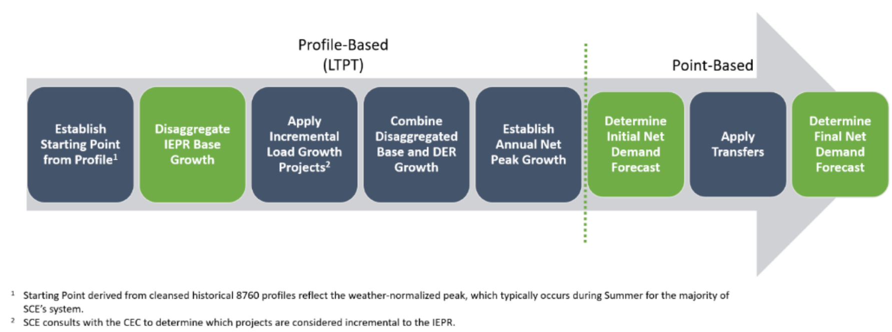
1. Historical Profile Reviews

The annual planning process activities begin with review of historical demand data which, for SCE, typically occurs after summer peak demand conditions have concluded. During this step, SCE engineers review recorded demand profiles of each distribution circuit and each distribution substation and analyze historical peak demands to determine if any abnormal conditions were present during the recorded peak period. If such conditions did occur, the engineers adjust abnormal data as needed to represent normal conditions. SCE uses these adjusted or "cleansed" demand profiles as starting points for subsequent steps in the planning process.

2. Load Growth & DER Forecasts

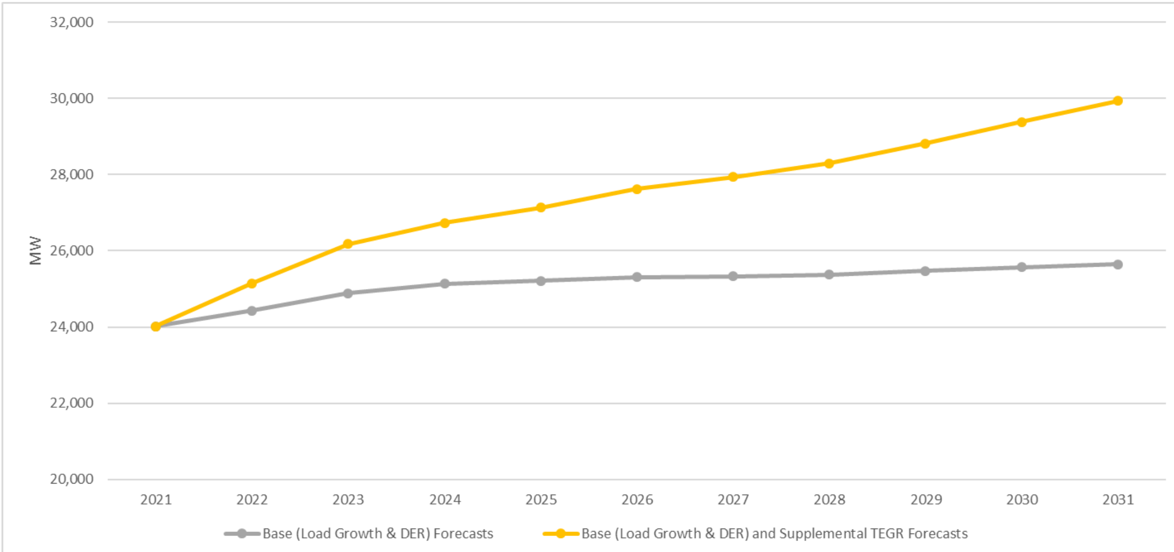
The next step in SCE's Distribution and Subtransmission Planning Process is to develop and apply 10-year load and DER forecasts for all distribution circuits, distribution substations, subtransmission lines, and load-serving transmission substations. A simplified diagram showing SCE's end-to-end distribution forecast process is shown in the following figure.

Figure II-6
SCE's End-to-end Distribution Forecast Process



The following sections further describe SCE's Load Growth Forecast Process, DER Forecast Process for DERs that Produce and Consume Energy, and the Supplemental Transportation Electrification Grid Readiness Forecast. The growth forecasts that result from these processes are provided in the following figure.

Figure II-7
Base (Load Growth & DER) and Supplemental TEGR Forecasts



a) <u>Load Growth Forecast Process</u>

The load growth process begins with development of a 10-year load growth forecast at the distribution circuit level. Pursuant to Commission guidance in the DRP, this load growth forecast is established through the disaggregation of the CEC's 2020 IEPR load growth forecast.[33] The CEC provides this forecast to SCE at the system-wide level, and not with the granularity necessary to account for localized electrical needs on the distribution and subtransmission systems. SCE and other stakeholders participate in the DFWG to discuss and develop methodologies to disaggregate system-wide forecasts to the distribution circuit level. SCE also incorporates additional load growth that may not have been fully reflected in the CEC forecast, which SCE considers incremental[34] to the IEPR forecast.

SCE's disaggregation methodology of the IEPR base load growth forecast encompasses specific local-area knowledge from the system planning engineers on developers' new projects, as well as econometric data relative to each planning area. Local-area knowledge is derived from SCE's system planning engineers working closely with developers of agricultural, commercial,

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[33] The process by which SCE develops this forecast is detailed in SCE's 2022 GNA Report filed in R.14-08-013 on January 13, 2023. SCE is providing the relevant sections of the GNA as a supplemental workpaper to this testimony. Refer to WP SCE-02, Vol. 07 Bk A, pp. 1-81 – SCE's Grid Needs Assessment Narrative.

[34] Refer to WP SCE-02, Vol. 07 Bk A, pp. 1-81, pp. 13-14 – SCE's Grid Needs Assessment Narrative.

industrial, and residential projects to understand the electrical needs of these developers' projects, timing of the projects, and the projected increases in demand that would be placed on SCE's distribution facilities in the area. These projected demand increases, based on information provided by the developers as well as institutional knowledge from SCE's past experiences with similar developments, are added into the IEPR forecast, resulting in an SCE load growth forecast.

b) DER Forecasting Process

Along with the development of a load growth forecast, SCE incorporates forecasts that account for other load-modifying inputs such as DERs, including energy efficiency, energy storage, demand response, Electric Vehicles (EVs), and distributed generation (DG), such as solar photovoltaic (PV) systems. Similar to the load growth forecast process described above, SCE utilizes the CEC-developed IEPR forecasts for these load-modifying inputs and disaggregates them to the distribution circuit level. Each of these DERs has a distinct load shape that impacts system needs in different ways, which is further differentiated by the volume of DERs forecasted and specific conditions of the local system. In some cases, forecasted adoption of DERs can help to reduce local constraints, such as solar PV offsetting daytime peaks, but at other times DERs can lead to new challenges, including emergence of a second peak or DER penetration reaching a point where two-way power flow can occur. For PV included in the 10-year forecast (2022-2031), SCE has incorporated an updated methodology[35] for representing the impacts (i.e., reductions) to peak demand. This change in methodology has resulted in updated values of the amount of solar PV output that is considered "dependable" and can be relied upon for planning purposes, also known as "solar PV dependability." The updated solar PV dependability values were determined based on (1) cross-sectional analysis of historical PV outputs for each hour of the day within a discrete operating region of SCE's territory and (2) regional output percentages for each hour empirically derived from the 10th percentile of each cross-section's data set. These calculated solar PV dependability values are grouped both regionally and seasonally in order to represent local climate conditions. The peak of the dependability profiles is not coincident with the system peak. The dependability profile peaks at 12:00 PM whereas the system peak occurs around 4:00 PM so solar contribution at system peak is significantly reduced. As an example of the updated methodology, at 12:00 PM in the San Jacinto region, 43% of the installed nameplate of solar PV can be considered "dependable" in Summer months and 33% in Spring months.

[35] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 82-89 – SCE's Dependable Photovoltaic Generation Methodology.

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

c) <u>Supplemental Transportation Electrification Grid Readiness (TEGR) Forecast</u>

Over past GRC cycles, SCE's load growth and DER forecasting and planning process has met historical needs given relatively modest and predictable customer growth. However, as discussed above and in Mr. Takayesu's Grid Policy testimony,[36] ambitious State decarbonization policies, particularly in electrifying the transportation sector (e.g., transportation electrification or "TE"), increase both the pace and uncertainty of electric load growth.

The most recent available Integrated Energy Policy Report (IEPR) for SCE's use for its grid planning process for this GRC cycle was the 2020 IEPR. Unfortunately, however, the State's electric load assessment for TE in the 2020 IEPR forecast used a methodology that does not incorporate recently approved policies, policies in development, or future anticipated policies. As a result of this approach, the forecast rates of EV adoption in the 2020 IEPR do not align with achieving the State's policy goals and targets, which impacts SCE's grid planning process since the IEPR forecast assumptions are a foundational element that shapes the demand forecasts that are used in grid planning.

Therefore, to supplement the 2020 IEPR forecast with a more accurate view of grid planning needs to achieve the State's goals and targets, it was necessary for SCE to develop a supplemental TE growth forecast[37] with TE assumptions that are also reflected in the CARB's 2020

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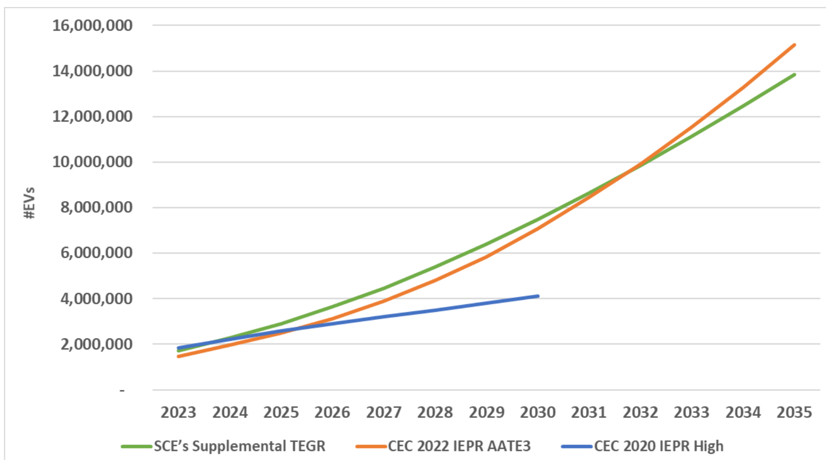
[36] See SCE-02, Vol. 01, Part 01 Grid Policy.

[37] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 90-106 – TEGR Forecast Development Workpaper. This supplemental forecast also supports increased building electrification. However, because close to 80% of the increased load growth relative to the base IEPR 2020 forecast comes from transportation electrification, we refer to this supplemental forecast as the Transportation Electrification Grid Readiness Forecast. For details, see the Workpaper on the development of the Supplemental Transportation Electrification Grid Readiness (TEGR) Forecast.

MSS and the CEC's AB 2127 EV Charging Infrastructure Assessment.[38] This approach is consistent with the most recent IEPR forecast development, specifically the 2022 IEPR,[39] in which the TE assumptions and resulting TE forecasts appear to align more closely with achieving the State's decarbonization policy goals and targets. The following figures plot the TE growth forecasts for Light Duty (LD) and Medium/Heavy Duty (MDHD) electric vehicles that were utilized in this GRC submittal versus the growth forecasts in both the 2020 and 2022 IEPRs. As these figures show, the TE growth forecast SCE utilized for this GRC aligns with the TE growth forecast in the 2022 IEPR.

Figure II-8
Comparison of Light Duty Vehicle Forecasts in California



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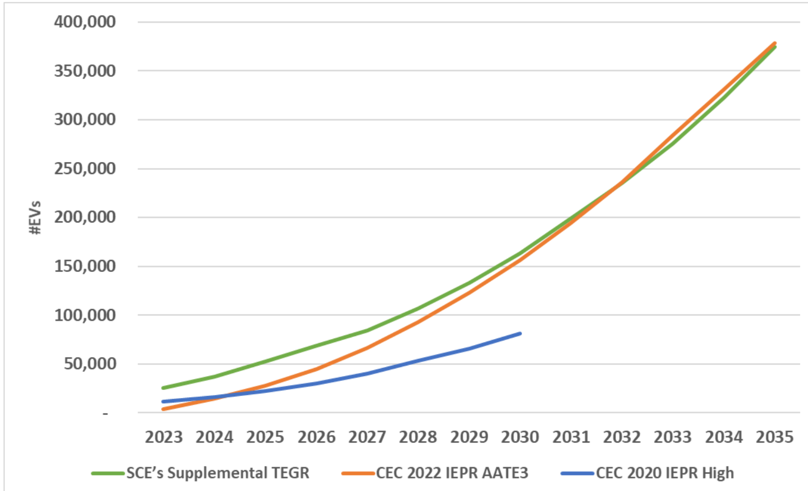
[38] Calif. Air Resources Board, 2020 Mobile Source Strategy (October 28, 2021), *available at* https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

Calif. Energy Commission, Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment (July 2021), *available at* https://efiling.energy.ca.gov/getdocument.aspx?tn=238853.

[39] California Energy Commission, Final 2022 Integrated Energy Policy Report (Feb. 2023), *available at* https://efiling.energy.ca.gov/GetDocument.aspx?tn=248998.

Figure II-9
Comparison of Medium & Heavy Vehicle Forecasts in California



In addition, the traditional grid planning process, as described in the annual DFWG, employs a top-down load allocation process of the IEPR demand forecast for disaggregation within SCE's service territory. This top-down allocation method is rather limited in reflecting customer specific characteristics and propensity. This allocation approach is generally sufficient to capture the growth of LD vehicles expected to charge primarily at Level 2 (slow) charging stations. However, for certain types of TE growth, this approach risks missing important local area specifics of where, when, and how much TE demand growth is expected to impact SCE's electric grid locally. This is critically important when considering the adoption of MDHD EVs, which can have significant grid impacts due to their larger charging requirements than LD EVs and with their expected clustering within industrial locations (e.g., fleet depots, warehouse, industrial garages, etc.) for charging. Other sources of TE growth that will result in significant grid impacts include new public charging stations for MDHD vehicles (e.g., truck stop charging), public fast charging of LD vehicles, and electrification of the Port of Long Beach.

Therefore, in addition to developing a supplemental TE growth forecast, SCE also augmented the top-down disaggregation with a bottom-up analysis with more resolution and granularity provided by additional customer characteristics to better understand local system needs and address this limitation in top-down disaggregation for the TE demand forecast. This included closely examining large fleet operators of MDHD vehicles and other commercial fleets in SCE's service territory and mapping their propensity for TE adoption to circuits. SCE also identified and incorporated truck stop locations, large warehouses, drayage companies, and estimated impact from known future deployment of DC fast chargers into the forecast. Adding the higher resolution with a bottom-up view of propensity at a more local site and customer-level greatly enhanced planning capabilities to better predict EV adoption locally, identify reasonably expected areas of high EV load growth, and assess and identify associated grid needs to support the charging demands.

Identifying reasonably expected areas of high EV load growth resulted in a review of impacts along and near major transportation corridors. The identified areas assessed in the TEGR analysis are where impacts are most likely to arise – particularly from the fleet electrification of MDHD vehicles. These identified areas were then further assessed with higher and more granular views of levels of adoption than the base 2020 IEPR TE assumptions. Anticipating where TE load impacts would be most significant resulted in approximately 10-15 percent of SCE's sub-transmission and distribution systems being included for proposed grid development as part of the TEGR analysis.[40] More than 90 percent of the selected locations are either along a major transportation corridor or have proximity to the ports, and close to 70 percent of the selected locations are in a disadvantaged community. While needs may arise in other areas as well, this assessment provides a reasonable, proactive assessment of the areas that are most reasonably expected to experience TE load impacts in order to support policy-based adoption levels.

In order to support developing a greater understanding of customer-specific adoption of the various TE fleet operator and TE charging station developers, SCE has already begun, and plans to continue, proactively engaging with these stakeholders. SCE has conducted various TE fleet operator and TE charging station developer engagements to gain additional insights on where, when, and how much TE load is being planned. In addition, SCE is planning to host additional TE fleet operator and charging station developer workshops in the future to better stay engaged on the development of TE load, which can be used to inform future demand projections.

TE load profiles can have a significant impact on the grid, dramatically changing the loading of a circuit. For the supplemental TE forecast and subsequent analysis, SCE assumed TE load profiles that closely resembles a time-of-use rate responsive load profile with EV owners leveraging opportunities to charge off-peak.

[40] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 107-113, TEGR Location Selection Workpaper.

For this GRC period, SCE's supplemental TE forecast models a 2.0% per year increase above the base growth forecast. When combined, the base forecast and the supplemental TE forecast results in a total growth forecast increase of approximately 2.9% per year through 2028.

3. Technical Planning Analyses to Identify Grid Needs

After the load and DER forecasts are developed, the next step in SCE's planning processes is to perform the necessary technical planning analyses to identify grid needs. These analyses determine whether the projected forecasts described above can be accommodated using existing distribution, subtransmission, and transmission facilities. When performing these technical planning analyses, SCE evaluates grid performance using planning criteria as the basis for designing a reliable system. The planning criteria is based on equipment loading limits (termed "planned loading limits") that consider the effects of loading on thermal, voltage, and protection limits under normal and emergency conditions.

These technical planning analyses consider peak load conditions as well as peak or "high" DER output conditions.[41] In addition, supplemental technical planning analyses were also performed to identify grid impacts under SCE's supplemental TE growth forecast. These are described in more detail below.

a) Peak Load Technical Planning Analyses

The technical planning analyses for peak load conditions are focused on identifying grid constraints driven by projected peak demand increases. For these analyses, SCE utilizes forecast peak load and incorporates an assumption on dependable DER output at the time of peak load conditions.

b) High DER Output Technical Planning Analyses

The technical planning analyses for high DER output conditions are focused on identifying grid constraints driven by distributed PV generation output. Since PV is currently the largest power-producing DER driving potential grid constraints with conditions such as "reverse power flow,"[42] high DER output forecasts currently focus on daytime hours. Each distribution feeder has a different minimum load level during those hours or "minimum daytime loading;" therefore, selecting a single

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

[42] "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.

hour to analyze the entire distribution system would not fully capture all DER-driven grid constraints that may arise due to different feeder behavior and types of customers on different circuits. Therefore, these technical planning analyses focus on when potential grid constraints are likely to occur throughout different hours of the day, on different days, and throughout the years that are studied.[43]

Furthermore, under the high DER output planning analyses, the output curves are further broken down into monthly curves for each region and the 95th percentile is used.[44] Identifying grid constraints that are expected to occur under high DER output conditions is necessary for SCE to plan for these conditions to reliably integrate DERs. Further, this study process incorporates analysis of different types of DERs and their respective profiles.

c) Transportation Electrification Grid Readiness (TEGR) Analyses

Over the last few years, as the result of the adoption of EVs, SCE has started to experience the effects of rapid deployment and growth of TE load on its electric grid. This TE load can be developed, deployed, and interconnected to consume large amounts of electric capacity on electric distribution feeders and distribution substation transformers that previously had low, steady, or moderate load growth. These types of load interconnections are creating large swings in power demand usage and are expected to require rapid deployment of additional grid infrastructure to meet interconnection customer timelines. For example, the following plot depicts actual examples of recent typical TE load interconnections that occurred on SCE's grid.

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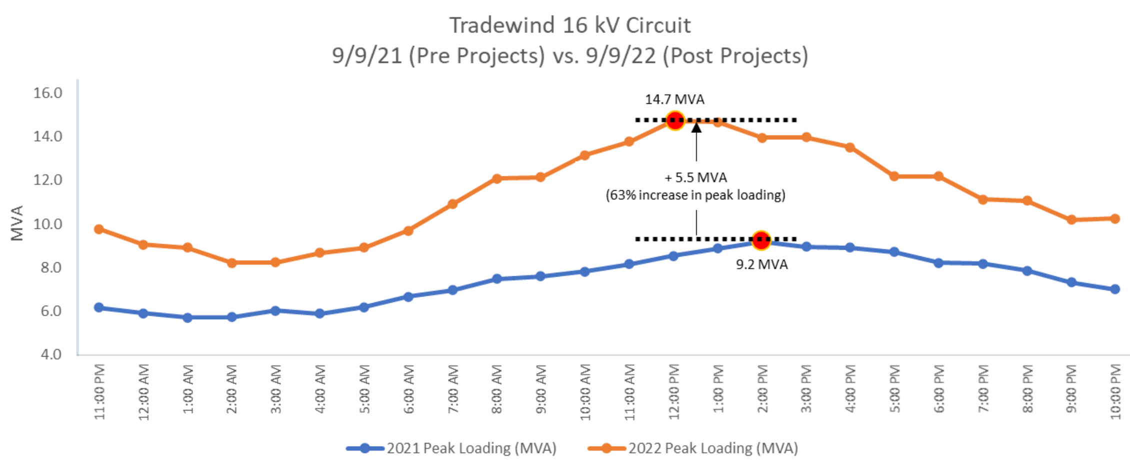
[43] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 114-120 – 8760 Analysis for High Distributed Energy Resources Planning Assumptions.

[44] SCE uses the 95th percentile as referenced in the California Distribution Resources Plan (R.14-08-013), 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.

Figure II-10
Example of Peak Loading Impacts due to TE Interconnections



In this example, charging station developers requested to interconnect TE charging station loads, which dramatically raised the peak loading of this circuit by approximately 63% (or approximately 5.5 MVA).[45] Based on SCE's current portfolio of TE interconnection requests, this magnitude or size of demand increase is not atypical. In fact, SCE's recent experience is that these interconnection requests are not only increasing in volume, but also in average size or magnitude. Since 2021 until present, SCE has received over 700 interconnection requests for TE loads of at least 500 kVA or larger, with the TE interconnection request demand increasing year over year with an average of 1.11 MVA in 2021, 1.53 MVA in 2022 and 1.68 MVA through the first quarter of 2023.

In addition, SCE has also experienced cases in which prospective TE charging infrastructure developers have submitted load interconnection requests for service requiring grid upgrade timelines exceeding the charging infrastructure developer's timeline for service need. For those cases, SCE informed those customers of delays to prepare the grid of up to two to three years, while various interim solutions, such as phasing limited amount of capacity service based on current grid constraints, were deployed. As part of this GRC submittal, SCE is exploring other temporary and/or relocatable infrastructure solutions, such as relocatable energy storage and mobile substations, as well as working with customers on load management solutions to help accelerate the ability to interconnect customers in a timely manner.

[45] The previous circuit peak was at 9.2 MVA and the new circuit peak after the TE load interconnected is at 14.7 MVA.

Although those interim solutions are necessary when load materializes faster than SCE can upgrade the grid with long lead-time projects, they are ultimately cost-inefficient stop-gap measures that are unable to either provide continued service over the long-term or address other local drivers in the area, such as aging infrastructure replacement, grid hardening for climate changes, and other service reliability needs. Given the uncertainty of the pace of potential TE load acceleration and the need for the grid to be ready to meet customers' adoption needs, proactively getting ahead of these long lead time projects is paramount to provide a measure of certainty for customers and enable customers' EV adoption and market transformation while maintaining grid reliability for the long term.[46] Otherwise, a reactive approach that waits to respond as needs arise may result in grid infrastructure requirements that cannot be feasibly deployed in a timely manner, do not meet other local area needs, and potentially result in delayed customer adoption of electric vehicles, disruption to commercial fleet operations, and delayed achievement of the State's decarbonization policy objectives.

Therefore, as discussed previously above,[47] in order to adequately prepare for the continued acceleration of load growth driven by our customers' TE adoption, SCE has undertaken planning analyses for this GRC utilizing a supplemental TE growth forecast (e.g., TE Grid Readiness or "TEGR" forecast), with the intent of identifying and developing grid infrastructure plans that ready the grid for this imminent growth of energy demand. From a planning perspective, given lengthy infrastructure project lead times of potentially a decade or more for large substations, it is critical to understand the limits of capacity availability alongside anticipated increasing levels of TE load. It is important to note that the TEGR forecast conservatively incorporates TE load profile assumptions that closely resemble a time-of-use rate responsive load profile, which models a form of managed charging or load management. SCE has also assessed an "unmanaged" charging load profile, which is an unconstrained charging profile (e.g., customers' EV charging not dependent or informed by time of use rates). The "unmanaged" case, as to be expected, would result in the need for significantly more infrastructure. As this comparison illustrates, SCE's ability to have visibility to, inform, and ultimately

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46 Ceres & the California Trucking Association, The Road to Fleet Electrification, *available at* https://www.ceres.org/sites/default/files/reports/2020-05/The%20Road%20to%20Fleet%20Electrification.pdf.

Alliance for Automotive Innovation, *Accelerating the Transition to Electric EV Infrastructure and Consumer Acceptance, available at* https://www.autosinnovate.org/about/advocacy/EV%20Infrastructure%20Initiative.pdf.

47 Refer to Section C.2.c.

influence customer charging behavior is central to our ability to keep grid infrastructure needs aligned with the more conservative, managed case. The investments needed to support these planning and operational capabilities are captured in SCE's Grid Modernization request in SCE-02, Volume 6.

4. Solution Identification and Evaluation

Following the Load and DER forecasting and Technical Planning Analyses processes, solution identification and evaluation activities are performed. The solution identification activities are categorized into the plans:

- Distribution Substation Plan (DSP)
- Transportation Electrification Grid Readiness (TEGR) Plan
- DER Driven Upgrades (DDU) Plan
- Subtransmission & Transmission Substation Plan (TSP)
- System Improvement Plan (SIP)

a) Distribution Substation Plan (DSP)

During the planning process for the distribution system, SCE performs analyses of system performance to identify system issues throughout the 10-year planning horizon that need to be addressed. The first five years of these system needs are identified in SCE's annually published GNA Report.[48] SCE also performs analyses to evaluate solutions to address the identified system needs throughout the ten-year planning horizon, which seek to maximize asset utilization and achieve the least-cost solutions to meet the electrical needs of its customers. The projects identified within the first 5 years are then included in SCE's annually published DDOR.[49,50] SCE's prioritization of solution alternatives for the Distribution Substation Plan (DSP) begins with evaluating the lowest cost alternatives first, and then sequentially reviewing the following potential solutions:

- Maximizing equipment utilization
- Distribution circuit upgrades
- Distributed energy resources
- New distribution circuits

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48 D.18-02-004.

49 The 2022 GNA and DDOR reports were filed on January 13, 2023. The 2023 GNA and DDOR reports will be filed in August 2023.

50 Refer to WP SCE-02, Vol. 07 Bk. A, pp. 121-122 – GNA and DDOR to GRC Project List Comparison Workpaper.

- Substation expansion
- New substations

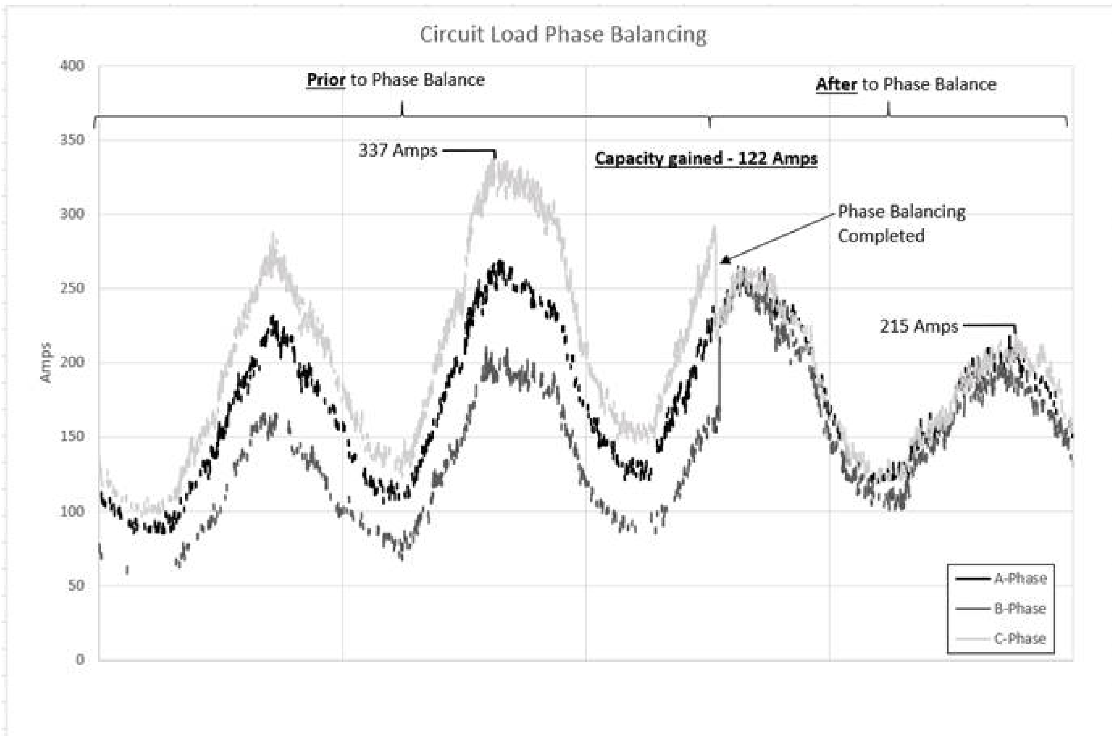
Throughout the progression, SCE develops a set of potential projects that can address the forecast distribution system needs. The technical feasibility of each proposed alternative is reviewed with various SCE stakeholders responsible for design, construction, and operation and maintenance. SCE uses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

(1) <u>Maximize Equipment Utilization</u>

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

Figure II-11 below shows an example of how peak loading on a circuit can be reduced by phase balancing. The figure shows two days of loading before balancing, one day during the balancing process, and one day after the balancing has occurred. While phase balancing is often a cost-effective solution, this may not always mitigate projected equipment overloads depending on the particular system characteristics, the load profiles of individual customers and DERs, and how and where they are physically connected to the circuits.

Figure II-11
Circuit Load Phase Balancing



If phase balancing is not an available option, SCE analyzes potential solutions that transfer load through switching to balance the load among the distribution circuits. This load balancing activity involves using existing sectionalizing devices to transfer a section of one circuit to an adjacent circuit. Distribution circuits are designed to include switches (normally operated in the "closed" position allowing power to flow through them) along the mainline of the circuit as well as having other switches (normally operated in the "open" position not allowing power to flow through them) located at the ends of the circuit at connection points to adjacent circuits. If neighboring facilities have sufficient reserve capacity, and if infrastructure exists that tie the circuits and/or substations together, SCE will consider performing load transfers through use of those facilities to reduce loading on the facilities that are projected to have loading violations. In doing so, SCE maximizes use of existing capacity and infrastructure. Phase balancing and load balancing are types of solutions that typically incur minimal to no capital expense and often solve identified overloads by increasing the utilization of installed assets. If existing infrastructure configurations cannot address the identified needs through phase balancing or load balancing, the next option is to consider upgrades to installed facilities or installation of new facilities to allow for the use of existing capacity reserves through the transfer of load between distribution circuitry and substations. This option is covered in the next section addressing distribution circuit upgrades.

(2) Distribution Circuit Upgrades

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

(3) Distributed Energy Resources

SCE intends to procure and install DERs to supplement traditional capital upgrades for locations where DERs are determined to be the preferred alternative. The primary DER that is expected to be used will be energy storage. SCE believes that energy storage can be a viable deferral opportunity compared to traditional infrastructure investments. The primary use case for DERs will be to install mobile energy storage facilities as a means of mitigating an overload to allow customers to interconnect while permanent infrastructure is being constructed. Projects expected to be offset by mobile or stational energy storage will be the construction of new circuits, substation transformer upgrades, or both. Energy storage will not be able to meet all needs such that no new wires solutions are constructed. The installation of new energy storage systems will be evaluated based on technical and financial analysis compared to the traditional wires solution to determine the least cost solution that meets the technical needs.

(4) **New Distribution Circuits**

If a distribution circuit upgrade project is not expected to be able to meet the need of a projected violation, or if the distribution circuit upgrade solution is economically impractical and would not meet the long-term needs of the area, SCE then considers constructing new distribution circuits. For example, if the average distribution circuit loading is projected to exceed distribution planning criteria and guidelines, further analysis is performed to consider if multiple existing distribution circuits in a general geographic area are forecast to reach or exceed capacity limits. These considerations may result in the need for a new distribution circuit.[51]

SCE constructs new distribution circuits as part of one of three types of projects: (1) standalone projects, (2) substation capacity increase projects, and (3) new substation projects. When the need for a new distribution circuit is identified to relieve load from other distribution circuits, the proposed new capacity is planned to not only allow for the transfer of load from the highly loaded existing circuits (in order to bring them to within acceptable planned loading limits), but also to provide circuit ties to increase operational flexibility.

(5) **Substation Expansion Projects**

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

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

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

combination with a new distribution circuit to offload a neighboring substation, instead of constructing a new substation.

(6) New Substation Projects

In some instances, a project to construct a new substation is the most cost-effective long-term solution. One example is if an addition of capacity to an existing substation through either an upgrade of equipment within the existing substation property or through an expansion of the substation property is not practical or feasible. Another is if multiple existing distribution substations in the same geographic region are already constructed to their maximum design capacities and are projected to experience continued load growth. A third is if a new development is being constructed in an area either isolated from existing electrical facilities or where there is insufficient electrical infrastructure. In each of the preceding examples, a new substation may prove to be the preferred economical solution to address the long-term needs of the area when compared to other feasible alternatives. In addition, SCE is considering interim bridging solutions, such as mobile substations, that can be rapidly deployed as a temporary solution to meet urgent customers service requests while the longer-term permanent substation is be constructed.

b) Transportation Electrification Grid Readiness (TEGR) Plan

As previously discussed, the TEGR Plan is SCE's proposed grid readiness plan to accommodate the State's policies around electrifying the transportation sector. Similar to the DSP described earlier, the TEGR Plan was also developed using a prioritization of solution alternatives framework that begins with evaluating the lowest cost alternatives first, and then sequentially reviewing the following potential solutions:

- Maximizing equipment utilization
- Distribution circuit upgrades
- Distributed Energy Resources
- New distribution circuits
- Substation expansion
- New substations

The TEGR Plan was developed under a 10-year planning horizon and, as customary in the planning process underlying the GRC, the TEGR analysis identified projects with operational dates that lie outside the GRC window. However, unlike prior GRCs, the TEGR analysis found among this set of projects with operational dates outside the GRC period a pronounced increase of substation A-Banks at the subtransmission level. This represents a dramatic and necessary increase in the volume of these projects. For example, under the base forecast, 1 new A-Bank subtransmission substation has been identified, while under the supplemental TEGR forecast, 4 new A-Bank subtransmission substations were identified. Furthermore, these identified new substations are long-lead time projects, which may take more than a decade to deploy, meaning that preparatory work such as planning, designing, siting, and licensing will need to begin within the 2023-2028 GRC cycle so that the projects are able to be completed and ready in time to serve the TE-driven customer load that is coming.

While the specific system infrastructure upgrades proposed from the TEGR analysis and represented in the TEGR specific sub-sections of Section II.D below resulted from the policy-based forecast and additional disaggregation methodologies described in II.C.2.c), even more projects may be on the horizon if customers and the market electrify on an even more accelerated pace at constrained locations than anticipated. At some locations, limitations in physical space at existing substations may present challenges to deploying future substation upgrade projects. To address this potential risk, in addition to the supplemental forecast and the refined bottom-up disaggregation methodologies to identify associated grid needs, the TEGR Plan also included a Maximum Electrification Potential Screening Review for distribution-level B-Bank substations. This screening review, which assumes the maximum potential for TE load to materialize (under both 50% and 100% fleet electrification adoption potential scenarios),[52] identified locations where TE-driven needs may arise outside of the planning cycle beyond the 10-year horizon, but for which we would need to plan ahead for the future given long project lead times – especially if that load materializes sooner than expected. Since this screening review applies to the time period beyond the current 10-year planning window, the purpose of this screening review is focused on identifying where additional land may be required to deploy future electrical infrastructure, rather than identifying the specific system infrastructure upgrades that will eventually be required.

As identified by this distribution-level B-Bank substation "maximum potential" screening analysis, there are cases of distribution-level B-Bank substations operating at the margin that may not be able to accommodate significant increasing TE load when it materializes given capacity constraints, even considering a full physical build out and upgrading of the existing substation. These

[52] While both 50% and 100% fleet electrification adoption potential scenarios were assessed, the needs identified in the DSP Substations Section II.D.1.d)(2)(a)(ii) from this analysis were based on the 50% fleet electrification scenario.

are cases where expansion or a new substation to accommodate the increasing additional TE load would require land acquisition. The TEGR maximum potential screening review identified at least two such cases for which land would be required to accommodate significant TE adoption levels in those areas (under the 50% fleet electrification potential scenario). These two instances are included in the DSP Substations Section II.D.1.d)(2)(a)(ii).

There are potentially many more such cases if sites and customers accelerate adoption even faster than expected. Given the long lead time of these projects, it may not be timely or feasible to wait until after the need ultimately materializes within the standard 10-year planning window to initiate the land procurement as doing so would (1) lead to delayed service interconnections, (2) inadequately meet customer needs, and (3) present a risk to commercial customers that may have regulatory compliance obligations to meet expected fleet vehicle transition timelines.

For these long-lead time projects with operating dates outside the GRC, it is essential that SCE begin the work on these TE-driven substation projects in this GRC cycle to accommodate the reasonably expected increased load, ready a reliable grid to support decarbonization policies and customer adoption of EVs, and ensure that the investments and required grid facilities needed to realize this significant market transition are deployed in an efficient and gradual manner. Grid-readiness and the availability of supportive grid infrastructure needed to power EVs are a primary concern for EV adopters,[53] and these factors are especially important for commercial fleets that have MDHD vehicles, with the largest of these fleets anticipated to be regulated by the State's Advanced Clean Fleet rule.[54] If these sizable TE load increases from this policy-driven industry transformation materialize and SCE has not completed these projects to ready the grid, it will slow down and potentially impede the State's policy objectives for combating climate change and may lead to severe consequences for other sectors within California's economy, such as increased supply chain challenges for personal and industrial goods and services.

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[53] Ceres & the California Trucking Association, The Road to Fleet Electrification, *available at* https://www.ceres.org/sites/default/files/reports/2020-05/The%20Road%20to%20Fleet%20Electrification.pdf.

Alliance for Automotive Innovation, *Accelerating the Transition to Electric EV Infrastructure and Consumer Acceptance, available at* https://www.autosinnovate.org/about/advocacy/EV%20Infrastructure%20Initiative.pdf.

[54] Calif. Air Resources Board, Advanced Clean Fleets, *available at* https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets.

It is important to note here that, as previously discussed, SCE assessed a "managed" and "unmanaged" charging profile as part of its TEGR analysis, where the "managed" profile closely resembles a time of use rate responsive load profile, while the "unmanaged" profile resembles a profile where customer charging can occur in an unconstrained fashion. SCE's Grid Modernization roadmap envisions that third party charge management/load management technologies will be deployed and operating in a coordinated fashion with SCE's Grid Management System (GMS) where "managed" charging will be more common. This GRC request for the Load Growth BPE investments assumes a "managed" charging profile consistent with SCE's Grid Modernization vision.[55] If SCE had instead assumed an "unmanaged" charging profile, the TEGR investments needed for load growth would be approximately ten to fifteen times higher than the TEGR investments proposed in this GRC submittal.

c) DER-Driven Upgrades (DDU) Plan

As part of the planning process, SCE analyzes high DER output conditions to determine whether system upgrades are necessary to accommodate the growth of DERs. The analysis utilizes the same distribution system planning thresholds, criteria, and practices as those used to evaluate peak load conditions. This includes utilizing the same thermal loading, voltage, and protection limits of distribution and substation equipment. Due to the nature and complexity of DERs in real-time, the analysis also identifies areas with higher DER adoption, which can impact the ability for SCE's grid operators to effectively shift load under normal, emergency or contingency conditions. Similar to load transfers, DERs need to be balanced across feeders to provide engineers and grid operators the necessary level of operational flexibility.[56] As a result of these impacts, SCE identifies circuits and substations with higher DER penetration and identifies the required upgrades in order to maintain adequate reliability and operational flexibility on an increasingly complex distribution grid.

d) Subtransmission Planning and Transmission Substation Plan (TSP)

After performing the planning activities for the DSP and developing the associated loading projections for each of the distribution substations, these values then become the necessary inputs to perform the planning activities associated with SCE's higher voltage assets: transmission substations and SCE's subtransmission lines and equipment as shown in Figure II-19. The

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[55] SCE's Grid Modernization vision is included in SCE's Grid Modernization request in SCE-02, Vol. 06.

[56] "Operational Flexibility" allows power system operators to respond in real-time to variations in load and system voltages to maintain system reliability pre-emptively or reactively.

Transmission Substation Plan (TSP), which includes the Subtransmission Line Plan, the A-Bank Plan, and the Subtransmission Volt-Amps Reactive (VAR) Plan,[57] captures the reliability needs of the higher voltage substations and equipment. Whereas the DSP uses the loading projected for the highest expected temperature within a ten-year period, referred to as a 1-in-10 year heat storm condition, the A-Bank Plan and Subtransmission VAR Plan use the loading expected for the highest expected temperature within a 5-year period, referred to as a one-in-five-year heat storm condition. This is because Subtransmission and Transmission networks and their facilities cover much larger geographic areas as compared to distribution substations and there is a lower probability that the entire area, and each distribution substation within that area, would experience the same extreme weather conditions at coincident times. Conversely, because distribution substations serve smaller geographic areas, there is a higher probability that several adjacent distribution substations may each experience similar extreme weather conditions at coincident times, resulting in a reduction in the ability for adjacent distribution substations to provide loading relief to each other. Thus, while distribution substation planning requires a higher value of capacity margin, the applicable criteria for the planning activities associated with the A-Bank Plan and Subtransmission VAR Plan allow for a reduction in the planning margins required to account for peak loading.

(1) <u>Subtransmission Lines Plan</u>

Subtransmission lines operating at 66 kilovolt (kV) or 115 kV deliver electricity from the low-voltage side of SCE's transmission substation transformers to the distribution substations. These subtransmission lines are interconnected together to form a network of lines that serve the distribution substations. A networked configuration provides multiple pathways to the distribution substations, which in turn increases the reliable delivery of power to the substations, allowing for the system to provide continuity of service during both normal system conditions, when all facilities are in-service, and during abnormal system conditions when electrical facilities may be out-of-service due to planned or unplanned outages. The objective of the Subtransmission Lines Plan is to provide sufficient 66 kV or 115 kV subtransmission line capacity to serve the projected peak load of SCE's distribution substations. Through power flow studies, the capacities of each subtransmission line

[57] 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.

are evaluated to determine if they can be safely operated within established loading limits under normal conditions with all facilities in service ("Base Case"), and 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 it is projected that a subtransmission line will become overloaded or that it cannot maintain adequate voltage, low-cost operational solutions are first considered, similar to the distribution system planning process. These include determining if existing infrastructure can be utilized to transfer customer load from highly loaded subtransmission lines to others with sufficient reserve capacity. Often this occurs through load transfers from one distribution substation to another using distribution circuitry. If such a solution is determined to be infeasible, a project may be initiated to expand, upgrade, or reinforce the subtransmission system to address the identified issues. Typical projects include replacing existing subtransmission conductors ("reconductoring") with higher capacity conductors, replacing limiting components such as switches or circuit breakers with those of higher capacities, constructing new subtransmission lines, and/or installing 66 kV or 115 kV capacitor banks at distribution substations.

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

(2) <u>A-Bank Plan</u>

SCE's load-serving substations that reduce voltage from the transmission level (220 kV or 500 kV) to the subtransmission level (66 kV or 115 kV) are termed "A-Bank" substations. These substations function as the interface points in between the transmission system and the generation units connected to it, and SCE's subtransmission systems and distribution substations. A-Bank substations contain transformers that reduce transmission-level voltage (220 kV or 500 kV) to lower levels (66 kV or 115 kV) that are compatible with the subtransmission networks that provide power to the distribution substations. SCE identifies any system-related issues and associated mitigations in its annual A-Bank Plan. The process is similar to SCE's DSP; however, the A-Bank Plan reviews the 500/115 kV, 220/115 kV, and 220/66 kV A-Bank substations over the ten-year planning horizon. The purpose of the A-Bank Plan is to identify potential transformer overload conditions and voltage criteria violations to avoid the risk of loading beyond their capabilities. The consequences of overloading these transformers could result in excessive degradation of transformer life or failures of the transformer or other associated equipment that could result in service interruptions to customers. A-Bank substations commonly serve many distribution substations over widespread geographic areas and are the primary source of power to these distribution substations. As a result, disruptions at A-Bank substations can have an even greater impact than that of distribution substations.

(3) Subtransmission VAR Plan

The objective of SCE's Subtransmission VAR Plan is to fully supply the reactive power needs of each of the 66 kV and 115 kV subtransmission networks including the A-Bank substations that serve them. This evaluation, like the Subtransmission Lines Plan and the A-Bank Plan, occurs using projected loading under one-in-five-year heat storm conditions and is intended to ensure there is sufficient reactive support to avoid reactive power deficiencies that adversely impact both the transmission and subtransmission systems. This is accomplished by comparing reactive power supplies (primarily 66 kV and 115 kV capacitor banks) against the projected reactive power requirements of the A-Bank substation transformers, subtransmission lines, and any large customers SCE serves directly at the subtransmission voltage level. When it is projected that a VAR deficiency will occur within the ten-year planning horizon, SCE reviews alternatives, which include installations of 66 kV or 115 kV substation capacitor banks. These capacitor banks are typically installed at the low-voltage side of SCE's A-Bank substations.

e) System Improvement Programs

The System Improvement Programs are programs that implement needed system improvements that are not included in the scope of the plans described above (i.e., DSP, TEGR, DDU, Subtransmission Lines, A-Bank, or Subtransmission VAR). These improvements vary from program to program and include upgrades to address localized circuit issues, distribution system reactive power needs including control of reactive power devices, and targeted upgrades to substation terminal and system protection equipment. The category of System Improvement Programs includes the following programs:

- Distribution Plant Betterment Programs
- Distribution VAR Program

- Distribution Volt Var Control Programs
- Substation Equipment Replacement Program
- DER Driven Circuit Breaker Upgrades Program

(1) <u>Distribution Plant Betterment</u>

Besides improvements and projects covered by SCE's Distribution Circuit Upgrades (DCU) program, needs for other upgrades arise because of isolated local reasons. These may be caused by a variety of scenarios, which could include changes in load profiles that drive localized low voltage problems, instances where new protection devices and switches are needed for safety and reliability, new residential developments that require a circuit voltage not present, or new street or freeway improvements. The Distribution Plan Betterment program is used to address these critical concerns that are outside of the needs covered under the DCU program.

(2) <u>Distribution VAR Plan</u>

Capacitor banks are installed throughout the distribution system to supply needed reactive power to help maintain adequate power factor and help supply customers sufficient voltage. In the Distribution VAR Plan, SCE reviews requirements for capacitor banks on distribution circuits for the upcoming year based on forecast load growth. Without a comprehensive Distribution VAR Plan, SCE would risk undersupplying the reactive power needs of the distribution system as demand for electricity continues to increase. Inadequate distribution VAR supplies would cause the need for subtransmission and transmission systems to supply required VARs to the distribution system, an undesirable condition based on the need for voltage stability. Under worst case conditions, voltage instability is mitigated by shedding load. The objective of the Distribution VAR Plan is to fully supply the peak reactive power needs of each of the distribution circuits under normal weather conditions; this means maintaining unity power factor (zero reactive demand) at each distribution circuit. These reactive power needs increase as load is added to distribution circuits. When a distribution circuit is forecast to have a VAR deficiency, SCE will design a capital project to install either an overhead or padmounted capacitor bank on the circuit, depending on the circuit configuration.

(3) <u>Distribution Volt VAR Control (DVVC)</u>

The Distribution Volt VAR Control (DVVC) Program centralizes control of the field and substation capacitors to coordinate and optimize voltage and VARs across all distribution circuits fed by a distribution substation. The DVVC program has several objectives, which include minimizing: (1) system-wide voltage, (2) energy consumption, and (3) capacitor switching, while maintaining overall customer Rule 2[58] service voltage requirements and operating within the local distribution field Programmable Capacitor Controls (PCC) settings. The DVVC is implemented as a centralized voltage and VAR control scheme through the Distribution Management System (DMS) and the Energy Management System (EMS), which controls the switching of existing capacitors in substations and on distribution circuits.

(4) Substation Equipment Replacement Program

The Substation Equipment Replacement Program (SERP) evaluates the adequacy of substation terminal equipment and system protection equipment, and proposes upgrades when deficiencies are identified. The SERP identifies substations where available fault current, or short-circuit duty, exceeds safe equipment ratings essential to the provision of safe, reliable service. SCE's electrical distribution system is designed to safely detect and isolate faults. Distribution system faults can be caused by natural events, equipment failures, or accidents caused by human error. When a fault occurs, dangerous levels of current flow from all electrical sources to the location of the fault. Due to the magnitude of fault current, a fault condition must be isolated quickly to restore safe operating conditions to the electrical system. Not isolating a fault quickly enough can cause major damage to distribution equipment, can cause catastrophic failure, and can seriously jeopardize public and employee safety. Substation circuit breakers are the most common devices used to isolate faults and are relied upon to interrupt the highest fault currents experienced on the distribution system. If they are incapable of interrupting expected fault currents, the circuit breaker(s) is/are likely to fail when those faults occur. Such failures can be violent and result in widespread and prolonged outages.

(5) DER-driven Circuit Breaker Upgrades

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

When a fault occurs near inverter-based resources such as DERs, higher levels of current flow from all electrical sources (i.e., generators) to the location of the fault. SCE assumes the level of fault contribution from DERs that is published in SCE's Integration Capacity

[58] Voltage as designated in the American National Standards Institute (ANSI) C84.1 standard and modified by California Rule 2.

Analysis (ICA)[59] in this analysis, as opposed to SERP, which only considers fault contribution from generators connected at the transmission and subtransmission voltage levels.

5. Deferral Opportunities

Pursuant to Commission guidance in the DRP, SCE annually publishes the projects identified within the first five years that address the system needs in the DDOR. This information, in conjunction with the GNA Report, provides data to the public to support competitive market participation to defer traditional infrastructure investments via competitively-sourced DERs. As further described in SCE-02, Volume 6, Grid Modernization, the five Engineering and Planning (E&P) tools and GMS collectively support the Commission's vision of deferring traditional wires solutions with DERs via the DIDF.

6. Implementation of Solutions

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

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

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[59] Refer to SCE-02, Vol. 06 for a description of ICA.

D. Capital Expenditures - Load Growth

The Distribution and Subtransmission Planning Processes evaluate the system needs under load and DER growth scenarios. The near-term and long-term reliability needs driven by load and DER growth are imminent as intense load demands clash with the challenges of expanding the modern grid.

In total, SCE is forecast to spend $3,208 million in total Load Growth BPE capital expenditures for the years 2023 to 2028, all of which is CPUC-Jurisdictional. Table II-1 shows this capital expenditure summary. As discussed in sections II.C.2.c), II.C.3.c), and II.C.4.b), the tables below include the results of the TEGR analysis which identified additional grid capacity projects to meet projected levels of Transportation Electrification load. These incremental projects are described below in the respective TEGR sections of the Distribution Substation Plan and Transmission Substation Plan.

Table II-1
Load Growth Capital Expenditure Summary[60,61,62]
(Total Company – Nominal $000)

	2023	2024	2025	2026	2027	2028	Total
Distribution Substation Plan (DSP)	$118,473	$183,132	$232,912	$354,742	$375,847	$270,813	$1,535,919
Transmission Substation Plan (TSP)	$58,921	$48,940	$143,207	$237,294	$352,185	$411,825	$1,252,372
System Improvements	$50,344	$56,270	$46,970	$40,430	$45,852	$47,860	$287,725
Land Rights Management	$920	$975	$983	$1,015	$1,030	$1,062	$5,984
Climate Driven Circuit Ties			$19,742	$19,908	$20,047	$20,339	$80,037
Totals	**$228,658**	**$289,317**	**$443,812**	**$653,389**	**$794,961**	**$751,899**	**$3,162,037**

1. Distribution Substation Plan (DSP) Forecast

The outcome of SCE's distribution planning process is a coordinated set of solutions to address 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 system needs, a set of infrastructure solutions resulting from the progression described in Section II.C.4.a) are considered to address the identified distribution system needs. This analysis resulted in the identification of $1,1589

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60 Refer to WP SCE-02, Vol. 07 Bk. A, pp. 123-124 Load Growth Capital Expenditure Summary.

61 An error was identified subsequent to the finalization of financial data. Therefore, the intended financial numbers that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. Errata will be submitted to align the financial numbers in testimony, standardized workpapers and the RO model at a future date.

62 The forecast incorporates an adjustment to reflect changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

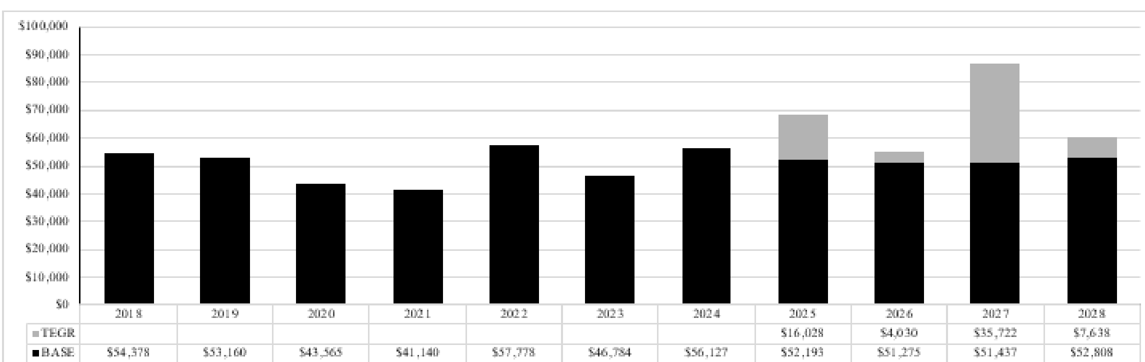
million in necessary DSP grid infrastructure solutions for the years 2023 to 2028. Furthermore, as discussed in Section II.C.4.b), SCE's distribution planning process also analyzed the grid impacts of the State's policies to accelerate and enable increasing amounts of transportation electrification via a supplemental transportation electrification demand forecast (TEGR forecast). This supplemental analysis (TEGR) resulted in the identification of an additional $377.354 million of DSP grid infrastructure solutions to prepare SCE's grid to meet the incremental transportation electrification load for the years 2023 to 2028. The TEGR projects are described in the respective TEGR Forecast sections below.

The combined total of the Load Growth Base and TEGR forecasts for the years 2023 to 2028 is $1,536 million, as shown in Table II-1 above.

a) <u>DSP Distribution Circuit Upgrades</u>

Figure II-12 below shows 2018–2022 recorded and 2023–2028 forecast capital expenditures for DSP Distribution Circuit Upgrades.

Figure II-12
Distribution Substation Plan Circuit Upgrades Capital Expenditure Summary[63]
WBS Element CET-ET-LGPFMTW
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TEGR								$16,028	$4,030	$35,722	$7,638
BASE	$54,378	$53,160	$43,565	$41,140	$57,778	$46,784	$56,127	$52,193	$51,275	$51,437	$52,808

(1) <u>Program Description and Need for Program</u>

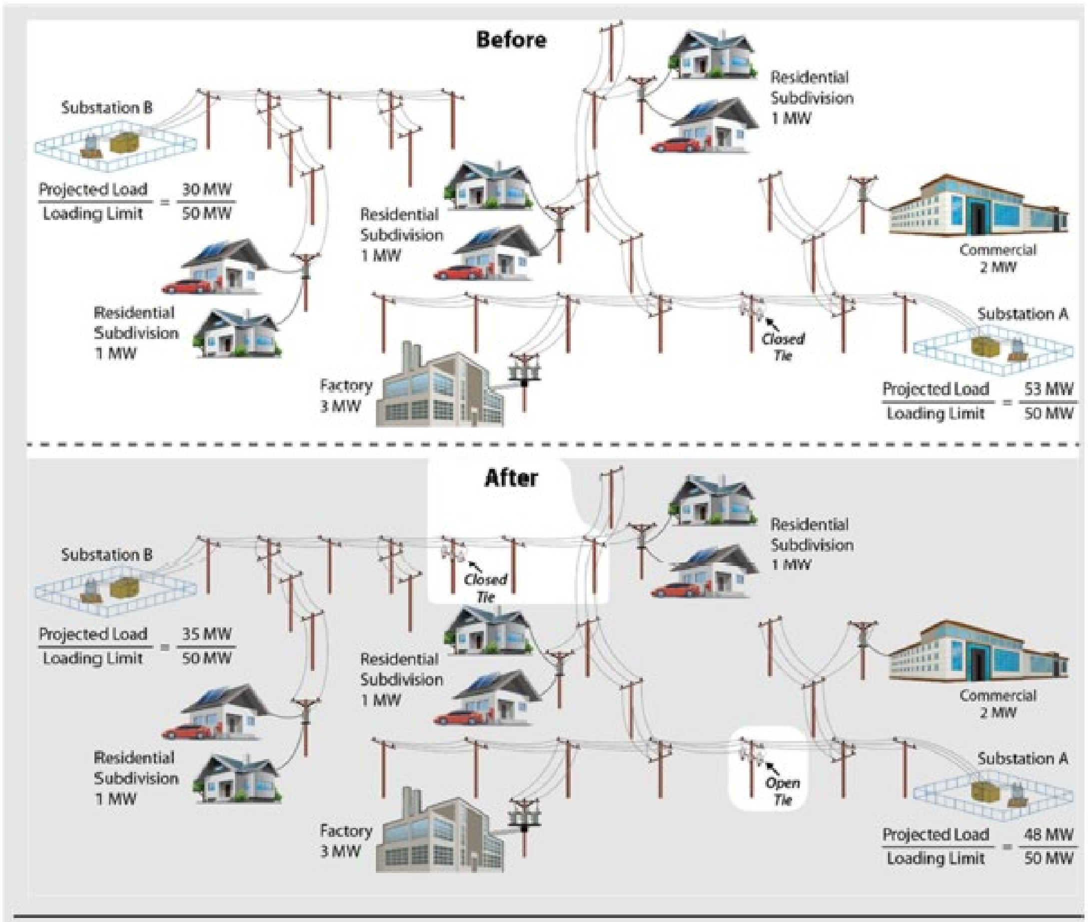
The DSP Distribution Circuit Upgrades program covers forecast expenditures for work outside of the substation required to relieve heavily-loaded distribution circuits

63 Refer to WP SCE-02, Vol. 07 Bk. A, pp. 125-126 – Capital Detail by WBS Element for Distribution Circuit Upgrades.

and substations expected to exceed distribution planning criteria limits. This includes all work required on distribution circuits to address distribution needs. This work enables distribution circuits to carry more electric current and/or make necessary transfers between distribution circuits and substations to mitigate situations where equipment is forecast to exceed capacity limits. Typical work includes installing new switches, upgrading cable or conductor, or installing new conductor to create circuit ties to facilitate load transfers between substations and circuits.

As an example, if Substation A is forecast to exceed its installed capacity and neighboring Substation B has capacity in reserve, but no circuit ties between the two exist or if circuit ties do exist but are not of sufficient capacity, a distribution circuit upgrade may be proposed to either create a circuit tie or to upgrade the capacity of existing facilities to allow for load transfers from Substation A to Substation B. This upgrade and associated load transfer would serve to lower the loading of Substation A to within its capacity limits by utilizing existing capacity reserves of Substation B. This scenario is depicted in Figure II-13.

Figure II-13
Distribution Circuit Upgrade Relieving Substation Capacity Limitation



In Figure II-13 before any upgrade or load transfer, Substation A is shown to be overloaded by 3 MW, while Substation B has 20 MW of reserve capacity. By adding a circuit tie between Substation A and Substation B, the projected overload condition of Substation A can be addressed by utilizing existing reserve capacity of Substation B, thus avoiding a substation upgrade project.

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

(2) <u>Basis for Capital Expenditure Forecast</u>

Figure II-12 above summarizes recorded costs for the years 2018 to 2022 for the Distribution Circuit Upgrades category and forecast costs for the years 2023 to 2028. The total forecast cost for the years 2023 to 2028 is $374.043 million (in nominal dollars). For the years 2018 to 2022, SCE's costs on this program averaged approximately $50 million per year (in nominal dollars). The forecast for the years 2023 to 2028 averages to $62.340 million per year (in nominal dollars).

Figure II-13 provides the forecast expenditures for 2023 and 2024 which are based on current scoped work. For 2025–2028, SCE uses a growth ratio to calculate the proportion of capital expenditures needed in a year relative to the forecast load growth costs in that year.[64] The growth ratio is calculated for each year using two key variables: (1) the costs of completed or planned distribution circuit upgrades from a given year, and (2) its corresponding load growth assumption.[65] The growth ratio is important for Distribution Circuit Upgrades due to the diversity of project scope that falls under this category as the result of the work performed varying significantly based on the need. It can include installing new switches, upgrading cable or conductor, or installing new conductor to create circuit ties to facilitate load transfers between substations and circuits. It can also include rearrangement of underground facilities to reduce underground cable temperature and installing or replacing equipment to increase the capacity of a distribution circuit. Typically, work for this category is scoped not more

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[64] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 127-129 – Distribution Circuit Upgrades Forecast Methodology.

[65] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 127-129 – Distribution Circuit Upgrades Forecast Methodology.

than one to two years prior to the distribution need and mitigates the identified need within that timeframe.

(a) Base Forecast - DSP Distribution Circuit Upgrades

SCE has identified a need for new projects with costs totaling $310.624 million for the years 2023 to 2028.

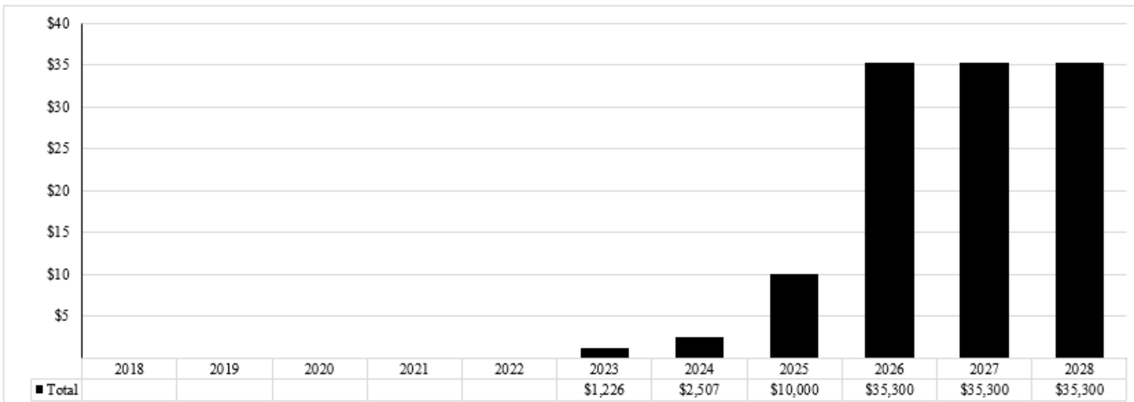
(b) TEGR Forecast - DSP Distribution Circuit Upgrades

As discussed in Sections II.C.2.c), II.C.3.c), and II.C.4.b), the supplemental forecast and additional disaggregation methodologies in the TEGR analysis resulted in additional overloads and project needs to address incremental transportation electrification load. These needs are incremental to the base load growth forecast and are necessary to accommodate reasonably expected transportation electrification in line with achieving policies and targets and supporting customer adoption. To support reliability in accommodating this additional identified TE load, SCE has identified a need for new projects with costs totaling $63.418 million for the years 2023 to 2028.

b) DSP Distributed Energy Resources (DERs)

Figure II-14 below shows the recorded costs for the years 2018 to 2022 and the forecast capital expenditures for the years 2023 to 2028 for DSP Distributed Energy Resources (DERs).

Figure II-14
Distribution Substation Plan Distributed Energy Resources (DERs) Capital Expenditure Summary[66]
WBS Element CET-PD-OTES-888800
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



(1) <u>Program Description and Need for Program</u>

When a DCU is not feasible, a process for evaluating DER solutions, primarily energy storage, is being formalized. Energy storage is a viable option for mitigation of forecasted overloads if the parameters of the overload are small in magnitude and limited in their frequency and duration. SCE proposes to install DERs at scale on the distribution system to mitigate overloads with parameters that fall into the DER's capabilities. If the forecasted conditions reveal a DER is not cost effective, a larger capital upgrade is required.

Two types of energy storage are being evaluated: permanent storage and relocatable storage. Permanent storage will be installed where facility overloads are persistent and remains within the DER's capabilities throughout the forecast period. Relocatable storage will be used as a short-term solution to facilitate customer interconnection while a permanent solution (DER or wire solution) is being constructed.

As described in the Energy Storage chapter in Exhibit SCE-02, Volume 6, the technological capabilities of Energy Storage can provide a number of benefits to the electric system, providing capabilities to optimize the grid, integrate renewable energy, or reduce GHG emissions. In the

66 Refer to WP SCE-02 Vol. 07 Bk. A, pp. 130-131 – Capital Detail by WBS Element for DSP DERs.

context of load growth, the use of energy storage will be focused on optimizing the grid, as it can be a tool to provide additional capacity on the electric system to defer infrastructure investments or to accelerate interconnection timelines for load growth requests. The inclusion of the capital request in this volume is to scale the use of energy storage for this application beyond what has been identified and demonstrated in SCE's Distribution Energy Storage Initiative (DESI) work. With the learnings to-date from our DESI work, and as demonstrated in our 2022 GNA/DDOR report, it is now appropriate to include a larger, scaled capital request so that energy storage can become a tool for SCE to reliably and timely integrate load into the electric system. Specifically, SCE expects rapid load growth due to transportation electrification service requests and will require solutions, such as utility owned distributed energy storage devices that can be deployed quickly to meet customer power service requests.

At the same time, there is a continued need to pilot energy storage in this GRC cycle, as separately described and justified in the Energy Storage chapter in Exhibit SCE-02, Volume 6, with an emphasis on value stacking and allowing energy storage to serve multiple use cases simultaneously. The capital forecasts in that Energy Storage chapter in Exhibit SCE-02, Volume 6 for pilots are distinct from the capital forecast being requested here.

(2) <u>Basis for Capital Expenditure Forecast</u>

(a) <u>Base Forecast – DSP DERs</u>

The analysis performed maintained the same planning standards except that forecasted profiles were compared to their respective loading limit rather simple point peak loading values. An energy storage device with a 1-megawatt (MW) peak and 4-megawatt-hours (MWH) energy capacity are the model parameters used to calculate the number of energy storage devices that would be needed to meet the projected grid needs, such as overloaded facilities. A list of assets with overloads and the number of energy storage units needed to address the projected overload was ranked from lowest number of energy storage devices to the most number needed. The list of circuits and substations with energy storage potential needs was compared to the ICA results and the locations where reverse power flow is known. A total of 36 energy storage devices is recommended to be procured and installed to address the projected facility overloads.

The analysis shows that relocatable energy storage will be the most viable use case of the DER program. Projected facility overloads tend to increase over time and more energy storage would be needed in future years. The ability to relocate energy storage will allow for operational flexibility to mitigate near-term projected overloads and enable customer interconnections on a timely basis while the permanent solution is being constructed. The energy storage systems have a high cost compared to wire solutions but will be able to be interconnected faster than the construction of the wire solution. An energy storage system can be installed relatively quickly, while a DCU will take more than a year and a new circuit will take multiple years. However, energy storage system costs are magnitudes larger than DCUs for the same peak capacity. Additionally, a new circuit cost that has at least 12 times the capacity cost is comparable to the cost of an energy storage system.

The forecast is based on the ability of SCE to install energy storage devices at scale and will ramp up deployment as the program becomes more mature. The capital expenditures under the base forecast for DSP DERs for the years 2023 to 2028 is $119.632 million.

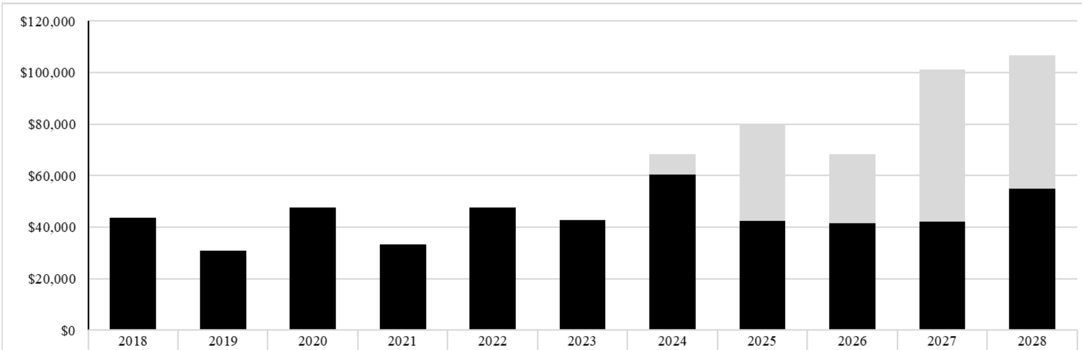
(b) TEGR Forecast – DSP DERs

TEGR utilized a DER solutioning tool to expand capabilities to evaluate and identify DER-based solutions. The DER tool utilized as inputs the projected loading and limits of select circuits and substations with capacity constraints (overloads) to determine DER alternatives in terms of technology, size, scoping, and estimated cost magnitude. The tool considered DER technologies such as standalone solar PV, energy storage, as well as co-located solar PV and storage. The tool also considered wires and storage hybrid solutions. The DER tool then calculated the most cost-effective DER-based alternative and compared the overall benefits/costs with a traditional, standalone wires solution. SCE utilized the DER tool to evaluate the general feasibility and cost-effectiveness of DERs versus traditional wire solutions to meet localized TE-driven capacity needs. Based on this analysis, no incremental capital expenditures for DSP DERs were identified for the years 2023 to 2028.

c) DSP New Circuits

Figure II-15 below shows the recorded costs for the years 2018 to 2022 and the forecast costs for the years 2023 to 2028 for DSP New Circuits.

Figure II-15
Distribution Substation Plan New Circuits Capital Expenditures Summary[67]
WBS Element CET-ET-LGCIMTE
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
TEGR							$8,076	$37,100	$26,768	$59,308	$51,886
BASE	$43,666	$30,758	$47,538	$33,207	$47,678	$42,800	$60,289	$42,443	$41,614	$42,076	$54,961

(1) <u>Program Description and Need for Program</u>

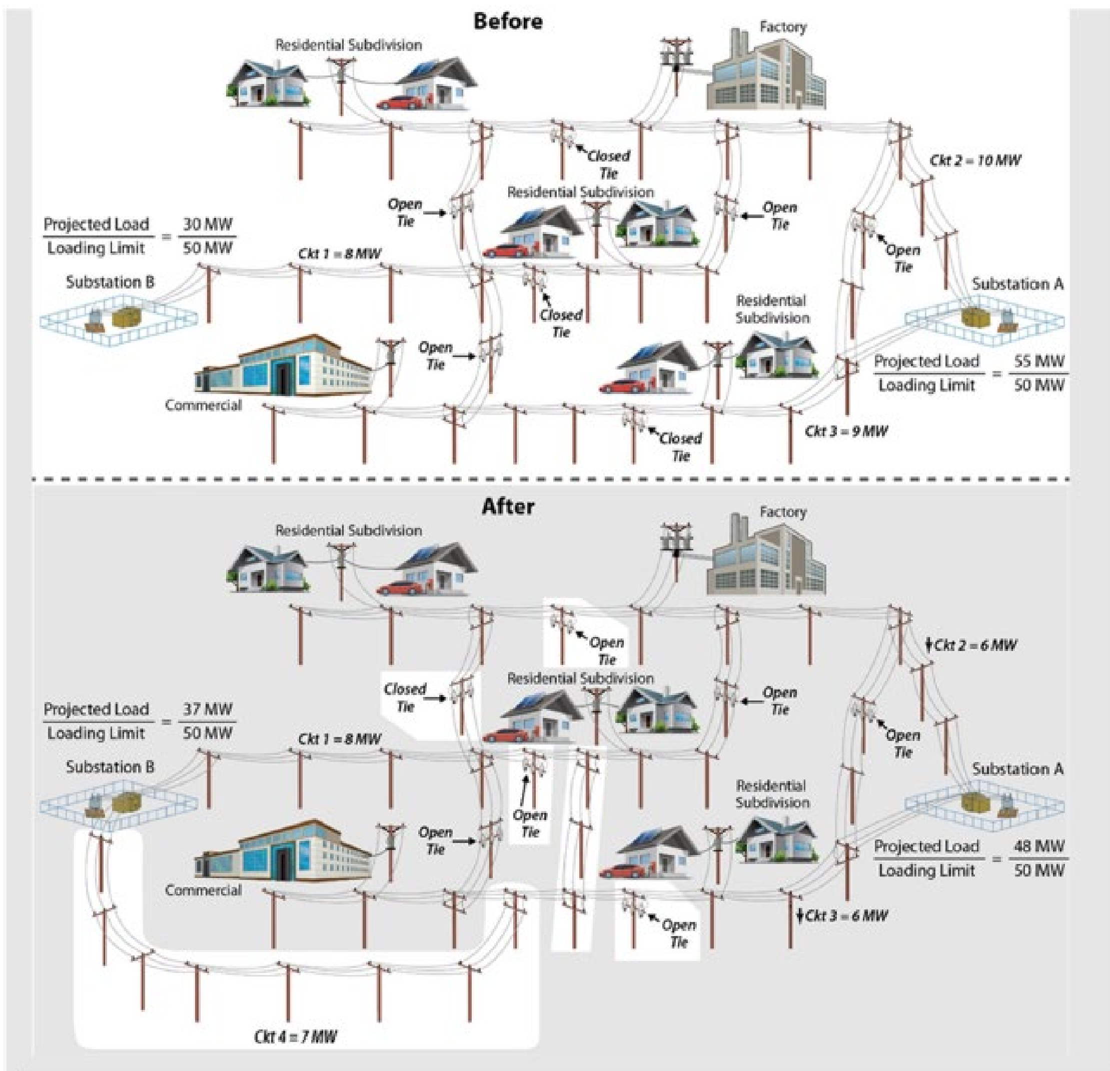
As part of the DSP Program, new distribution circuits are required to provide new capacity outside the substation fence in areas where multiple distribution circuits in the same geographical region are expected to exceed capacity; to serve new residential or commercial developments in areas with no existing electrical infrastructure; and to relieve existing circuits projected to exceed capacity in geographically isolated areas with limited usable circuit ties to transfer load.

As described in Section II.D.1.a)(1), new distribution circuits may also be used to relieve distribution substations expected to exceed capacity by transferring existing customers to a neighboring substation through the circuit. When existing circuitry does not have adequate capacity, new distribution circuits are needed to accomplish this transfer of customers. As an example, if Substation A is forecast to exceed its substation transformer capacity limit and it is determined that adjacent Substation B has available substation transformer capacity that can provide loading relief to Substation A through balancing loads between them, SCE evaluates means to transfer load from Substation A to Substation B through the existing distribution circuitry between the two substations. If there is insufficient distribution circuit capacity to accommodate this, SCE evaluates whether construction of a new distribution circuit is economically preferred over other alternatives such as

[67] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 132-133 – Capital Detail by WBS Element for DSP New Circuits.

adding substation transformer capacity to Substation A or constructing a new distribution substation. If for example, the distance between Substation A and Substation B is significant and the corresponding new distribution circuit scope is substantial, the cost to construct a new distribution circuit may exceed other alternatives such as substation transformer capacity addition. The option of a new distribution circuit as a solution to offload a neighboring substation is compared to the cost and overall effectiveness of a substation capacity addition project to determine the preferred alternative to meet the long-term needs of the area. Figure II-16 represents a graphical depiction of the example.

Figure II-16
DSP New Circuit Used to Offload Substation



In the pre-project condition, Substation A is projected to be overloaded by 5 MW and Substation B has 20 MW of reserve capacity. The loading on the existing circuits that tie between the two substations are highly loaded, cannot be sufficiently offloaded to other circuits, and are unable to be further upgraded. In this example, a new distribution circuit could be constructed from Substation B in a manner than could perform several functions. Properly designed, it would provide a means to connect to both the highly loaded circuits from Substation A and Substation B to transfer load from those circuits to it thereby reducing the circuit loading on those circuits. Additionally, as it would provide loading relief to the highly loaded circuit(s) from Substation A, it in turn provides the needed loading relief to the substation transformers of Substation A. The post-project condition results in an infrastructure addition of a new distribution circuit effectively addressing capacity deficiencies of Substation A. This is performed by utilizing available capacity of Substation B with the net result being the desired reduction of loading at Substation A to within acceptable loading limits while also maintaining the loading at Substation B to within acceptable loading limits. The new distribution circuit also adds operational flexibility to the area by reducing loading on the highly loaded circuits impacted, thereby increasing their transfer capability, which is especially important during unplanned outages while restoring service.

(2) <u>Basis for Capital Expenditure Forecast</u>

Figure II-15 above shows the historical and forecast costs for construction of new circuits. The cost of the new circuit has been removed from the substation capacity projects to show the new circuit forecast cost specifically. The capital expenditure forecast for DSP New Circuits is $467.319 million for the years 2023 to 2028. Under both the base forecast and TEGR forecast, the forecast for new circuits is driven by future load interconnections associated with existing circuitry and associated B-Bank substations within the forecasting process. When the load forecast exceeds the loading limit of an existing asset, the least cost mitigation is proposed. In general, large customers will not be able to be accommodated with a DCU, so a new distribution circuit will be needed to offload the existing circuitry.

(a) <u>Base Forecast - DSP New Circuits</u>

Based on the need identified in the DSP process, SCE estimates the cost of new distribution circuits. For circuits that have a need identified approximately two years out, SCE develops detailed plans based on the specific characteristics of the project. The cost estimate for new circuits needed beyond two years are typically estimated using historical costs, since detailed design and cost estimates are not yet completed.[68]

Costs to construct a new circuit vary depending on several factors such as whether the circuit is overhead or underground, the length of circuit, and geographic location. The voltage of the new circuit is another large contributor in the variation of the cost of a new circuit. New 33 kV circuits are typically more expensive than 12 kV or 16 kV circuits. This is due to the need for larger equipment and larger facilities to accommodate the higher voltage. The average historic unit cost for 12 kV and 16 kV circuits is $3.204 million and for 33 kV circuits is $7.741 million.[69] For new circuits, SCE's forecast reflects the timing of designing and constructing new distribution circuits. This is becoming increasingly complex due to environmental and permitting requirements of local jurisdictional agencies.

To allow sufficient lead time to complete construction of a new circuit, SCE begins the design process at least one year before the need date for the circuit. Typically, SCE plans to spend approximately 10 percent of the cost of a new circuit on early planning and design work one year prior to the operating date of the circuit, and the remaining approximately 90 percent to complete construction in the year that the circuit becomes operational. SCE has identified 69 new necessary distribution circuit projects with costs totaling $284.182 million for years 2023 to 2028.

(b) TEGR Forecast - DSP New Circuits

As discussed in Sections II.C.2.c), II.C.3.c), and II.C.4.b), the supplemental forecast and additional disaggregation methodologies in the TEGR analysis resulted in additional overloads and project needs to address incremental transportation electrification load. These needs are incremental to the base load growth forecast and are necessary to accommodate reasonably expected transportation electrification in line with achieving State policies and targets and supporting customer adoption. To support reliability in accommodating this additional identified TE load, SCE has identified 33 necessary new distribution circuit projects with costs totaling $183.137 million for the years 2023 to 2028. Estimated costs of these new projects are based upon the same methodology used for the Base Forecast.

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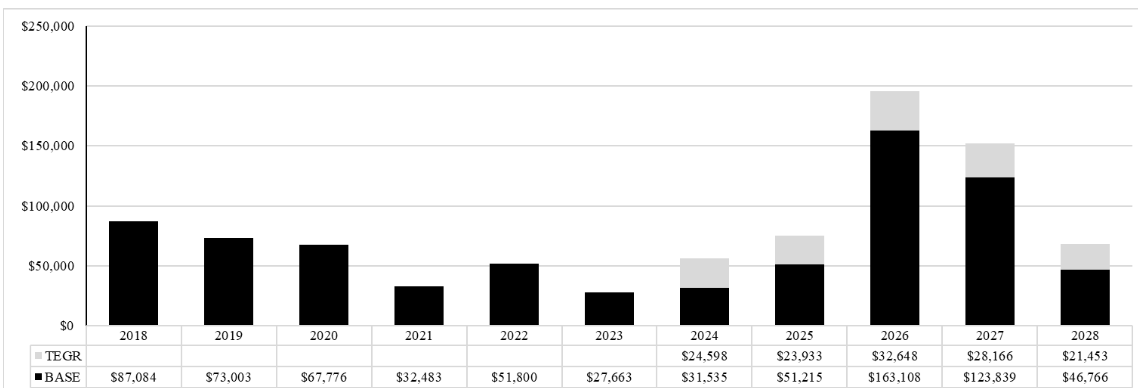
[68] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 134-137 – Distribution Substation Plan New Circuits Forecast Methodology.

[69] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 134-137– Distribution Substation Plan New Circuits Forecast Methodology.

d) DSP Substations

Figure II-17 below shows the recorded costs for the years 2018 to 2022 and the forecast costs for the years 2023 to 2028 for DSP Substations. The figure provides DSP Substation costs SCE has already incurred (i.e., expenditures made in 2022 or prior years for projects completed in the 2023-2028 period) and forecast costs for projects planned to be completed through 2028. The capital costs for each of the projects are presented in the appropriate tables in Table II-2.

Figure II-17
Distribution Substation Plan Substations Capital Expenditures Summary[70,71,72]
WBS Element CET-ET-LGSU-846500
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



(1) Program Description and Need for Program

As described in Section II.C.4.a)(6), SCE identifies required substation projects through the Distribution Substation Planning process when lower-cost solutions, such as distribution circuit upgrades or new circuits, do not adequately address an overload. Substation projects include capacity additions or upgrades to facilities at existing substations and within the existing

[70] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 138-171 – Capital Detail by WBS Element for DSP Substations.

[71] An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. Errata will be submitted to align the financial numbers in testimony, standardized workpapers and the RO model at a future date.

[72] In the course of finalizing this testimony, SCE identified minor inconsistencies for some projects between the forecast costs listed in system workpapers versus supplemental workpapers. SCE will address those inconsistencies in forthcoming errata.

perimeter of the substation property, additions or upgrades that require perimeter expansion of the substation property, and new substations.

Distribution substation expansion projects come in two categories: (1) installation of new, or upgrades to existing, substation equipment within the existing fenced property of a substation (section 2.b below); and (2) installation of new, or upgrades to existing, substation equipment at a substation that requires additional substation property and/or expansion of its existing property to accommodate the capacity increase (section 2.c below). Most commonly, the preferred economical solution is to upgrade an existing substation within the existing property prior to proposing to upgrade an existing substation by expanding the property. However, sometimes the scope, costs, or other impacts required to upgrade or expand an existing substation may be prohibitive when compared to the construction of a new substation. These could include such things as power system limitations, limited available space to expand the property, community impacts, and/or environmental impacts. New substation projects are covered in section 2.d below.

(2) <u>Basis for Capital Expenditure Forecast</u>

This section provides respective cost details and project summaries for both the base and TEGR forecast that together comprise the DSP Substations capital forecast. The section begins with an overview of all projects (section a). It then summarizes projects that can be constructed inside the perimeter of the substation (section b), projects requiring perimeter expansion (section c), new substations (section d), and, finally, the licensing status of new substations and substations requiring perimeter expansion (section e).

(a) <u>Overview of DSP Substations Projects</u>

This section provides an overview of all the DSP Substations projects for the respective base and TEGR forecasts. Figure II-17 above shows the historical and forecast costs for DSP substation projects. The capital expenditure forecast for DSP Substations is $574.924 million for the years 2023 to 2028. Projects with less than $3 million are not discussed here but are included in workpapers.[73,74] Furthermore, projects with costs in the years 2023 to 2028, but that have in service dates beyond 2028, are not discussed.[75,76]

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[73] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 172-173 – Base DSP Substation Projects Less than $3M Costs.

[74] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 174-175 –TEGR DSP Substation Projects Less than $3M Costs.

[75] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 176-177, TEGR DSP Substation Projects Outside GRC Window.

[76] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 178-179, Base DSP Substation Projects Outside GRC Window.

(i) Base Forecast

Table II-2 below provides DSP Substations costs already incurred (i.e., expenditures made in 2022 or prior years for projects expected to be completed in 2023 – 2028) and forecast costs for projects planned to be completed through year 2028 under the base forecast.

Table II-2
Base Forecast - DSP Substation Capacity Projects Capital Expenditure Summary[77]
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Operating Date	Prior	2023	2024	2025	2026	2027	2028	Total
1	8101	Increase Substation Capacity	Jun-23	11,202	1,761	0	0	0	0	0	12,962
2	8043	Increase Substation Capacity	Jun-23	46,554	5,723	3,000	0	0	0	0	55,277
3	8330	Increase Substation Capacity	Jun-23	2,805	1,188	0	0	0	0	0	3,993
4	8388	Increase Substation Capacity	Aug-23	452	1,991	9,201	0	0	0	0	11,645
5	8374	Increase Substation Capacity	Dec-23	238	1,861	1,781	0	0	0	0	3,879
6	8386	Increase Substation Capacity	Dec-23	2,482	1,659	0	0	0	0	0	4,142
7	8360	Increase Substation Capacity	Jun-24	413	5,756	2,916	0	0	0	0	9,085
8	DSP35666	Increase Substation Capacity	Jun-25	0	188	1,353	2,383	0	0	0	3,925
9	8481	Increase Substation Capacity	Jun-25	18	168	1,677	1,509	0	0	0	3,371
10	DSP33773	Increase Substation Capacity	Jun-27	0	0	0	145	1,338	1,522	0	3,005
11	4800	New Substation	Jun-28	4,381	1,180	6,193	8,234	42,508	30,059	31,726	124,281
12	8256	New Substation, New Subtransmission Line, New Circuit	Jun-28	8,261	1,365	1,395	33,653	111,909	85,361	6,983	248,927
13			Subtotal	76,807	22,840	27,516	45,924	155,756	116,941	38,709	484,493
14		Projects with CPUC-jurisdictional cost < $3M		2,615	4,824	4,019	2,189	725	786	0	15,157
15		Projects with operating date outside of GRC window		0	0	0	1,988	3,975	2,789	1,202	9,953
16			Total	79,422	27,663	31,535	50,101	160,455	120,515	39,911	509,602

SCE has identified 12 DSP substation capacity projects with costs equal to or greater than $3 million with a total cost of $484.493 million. The projects are separated into three categories: a) substation capacity projects without perimeter expansion, b) substation capacity projects requiring perimeter expansion, and c) new substations.

(ii) TEGR Forecast

As discussed in Sections II.C.2.c., II.C.3.c, and II.C.4.b, the supplemental forecast, additional disaggregation methodologies, and the maximum electrification potential substation screen in the TEGR analysis resulted in additional overloads and project needs to address incremental TE load. These needs are incremental to the base load growth forecast and are necessary to accommodate reasonably expected TE growth in line with achieving State policies and targets and projected customer adoption.

Table II-3 below provides DSP Substations forecasted costs to support reliability in accommodating this additional identified TE load. SCE has identified 5 substation capacity expansion projects with costs equal to or greater than $3 million and the total cost for these projects is $124.663 million. Forecasted costs of these new projects are based upon unit costs

[77] Refer to WP SCE-02, Vol. 07 Bk. A, pp. 180-247 Base Substation Capacity Projects.

of similar prior installations. Similar to the base forecast, the projects are separated into three categories: a) substation capacity projects without perimeter expansion, b) substation capacity projects requiring perimeter expansion, and c) new substations. The tables in the following subsections provide additional scope description and justification for each project in these categories.

Table II-3
TEGR Forecast - Substation Capacity Projects Capital Expenditure Summary
(Total Company – Nominal $000)[78]

Nominal $000

Line No.	Project No.	Project Name	Operating Date	Prior	2023	2024	2025	2026	2027	2028	Total
1	DSP35818	(TEGR) Sunnyside 66/12 kV (D) - Bank Replacement	Jun-26	0	0	157	1,123	1,979	0	0	3,259
2	DSP35812	(TEGR) Mt. Tom 55/12 (D) - Bank Replacement	Jun-27	0	0	0	161	1,154	2,033	0	3,348
3	DSP35829	(TEGR) New 66/12 kV (D) Substation % Hinson System	Jun-28	0	0	8,678	10,034	13,430	15,522	11,737	59,402
4	DSP35807	(TEGR) New 33/12 kV (D) Substation % Kramer System	Jun-28	0	0	7,821	5,876	7,419	4,845	3,105	29,067
5	DSP35822	(TEGR) New 33/12 kV (D) Substation % Vista System	Jun-28	0	0	7,861	6,135	7,641	4,845	3,105	29,587
			Subtotal	0	0	24,517	23,329	31,623	27,245	17,948	124,663
		Projects with CPUC-jurisdictional cost < $3M				81	603	1,025			1,709
		Projects with operating date outside of GRC window							920	3,506	4,426
			Total		0	24,598	23,933	32,648	28,166	21,453	130,798

Projects with costs in the years 2023 to 2028, but which have forecast in service dates beyond year 2028, are not discussed. The total cost for these projects (e.g., in-service date beyond 2028) is $4.426 million for the years 2023 to 2028.[79] This forecast amount includes costs associated with two substation capacity expansion projects with $3.6 million of the $4.4 million representing land acquisition costs for these projects in the years 2023 to 2028. As discussed in Section II.C.4.b, the TEGR analysis, through the Maximum Electrification Potential Screening Review, identified substations operating at their capacity margin that will likely need to accommodate significant increasing TE load. When this TE load materializes at these substations, it may not be possible to expand station load serving capacity to meet this expected TE growth without physically expanding the substation footprint. To address this issue, SCE has identified two substations that will require proactive land purchases in between 2023-2028 to accommodate future expansion to accommodate forecast TE load growth.

(b) <u>Substations Without Perimeter Expansion</u>

The subsections below list the DSP Substations projects, for both the base and TEGR forecasts, where the substation capacity increase does not require the existing substation perimeter to be expanded. Examples of these types of projects include such things as

[78] Refer to WP SCE-02, Vol. 07 Book A, pp. 248-321 – TEGR Substation Capacity Projects.

[79] Refer to WP SCE-02, Vol. 07 Book A, pp. 176-177, TEGR DSP Substation Projects Outside GRC Window.

replacement or upgrades of substation transformers, circuit breakers, or other capacity-limiting equipment and additions of facilities required for new distribution circuits.

(i) Base Forecast

Table II-4 below itemizes the nine DSP projects, identified through the base forecast, that can be constructed inside the existing perimeter of the substation. These projects are classified as "Substation Modification Projects" and have been reviewed and determined not to require General Orde (GO) 131-D licensing activities. Table II-4 below provides a brief scope description and justification for each project with in-service dates within the 2023-2028 GRC period. The total capital expenditures under the base forecast for DSP substations without perimeter expansion with in-service dates within the years 2023 to 2028 is $6 million.

Table II-4
Base Forecast - 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	Lancaster 66/12	8101	2023	City of Lancaster	Onion Cultivation Project submitted a request to SCE for an Advanced Engineering Analysis to determine feasibility and identify a manner of service for their project. As described by the customer, the Onion Project plans to develop 12.85 acres of vacant land beginning November 2017. The company anticipates subdividing the property into (5) 30,000 sq. ft. buildings.	Jackman, Kingtree, Medallion, Phillips, Queensland, and Target 12kV circuits are projected to reach 102%, 113%, 104%, 102%, 108% and 114% respectively in 2023 under 1-in-10 weather conditions	Install - 11.2 MVA	$ 12,962
2	Sun City 115/12	8330	2023	City of Menifee	Negative reserve at Sun City due to load growth. DSP new circuit of offload circuits out of Newcomb 115/12 Substation.	Newcomb 115/12 Substation is projected to reach 112% in 2023 under 1-in-10 weather conditions Bradley, Equinox, and Lusk 12kV circuits are projected to reach 114%, 104%, and 118% respectively in 2023 under 1-in-10 weather conditions	Install - 28 MVA capacity Install - (1) 12.0 kV circuit	$ 3,993
3	Hathaway 66/12	8388	2023	City of Long Beach	An updated Substation Capacity Analysis report determined that the operating bus and No. 1 transformer bank is overloaded	Hathaway 66/12 Substation is approaching capacity limitations in 2023 under 1-in-10 weather conditions.	Upgrade - 12kV Operating bus Install - 8 MVA capacity Install - 4.8MVAr Cap Bank	$ 11,645
4	Archibald 66/12	8374	2023	City of Ontario	ffload existing circuits, and a new 4.8 MVAR capacitor b	Bravon, Creekside, Hofer, and Kropp 12kV circuits are projected to reach 106%, 102%, 125%, and 104% respectively in 2023 under 1-in-10 weather conditions	Install - (1) 28 MVA Transformer Install - (2) 12 kV circuits Install - (1) 4.8 MVAR substation capacitor	$ 3,879
5	Roadway 115/12	8386	2023	City of Adelanto	-14 MVA transformers with 2-28 MVA transformers to	Kingpin 12kV circuit is projected to reach 165% in 2023 under 1-in-10 weather conditions	Replace - (2) 14 MVA transformers Install - (2) 28 MVA transformers Install - 4.8 MVAR Substation Capacitor. Install - (3) 12 kV circuits	$ 4,142
6	Pebbly Beach 2.4/12	8360	2024	City of Avalon	The #1 bank transformer at Pebbly Beach Generating Station (PGBS) is currently a single point of failure for the entire Island's electrical system. The Island is electrically isolated from SCE's mainland electrical system. The loss of the #1 bank will result in a loss of electricity, water (drinking water and fire fighting water will be unavailable), gas and sewage systems to the Island's 4000 residents and tourists.	Pebbly Beach 2.4/12 Substation is projected to reach 147% in 2024 under 1-in-10 weather conditions	Replace - (6) single phase 1.25 MVA transformers Install - (2) 3 phase 7.5 MVA transformers	$ 9,085
7	North Oaks 66/16	DSP35666	2025	City of Saugus	Large EV growth and economic develop in the area requires an increased capacity to continue to serve customer load	North Oaks 66/16 Substation is projected to reach 111% in 2025 under 1-in-10 weather conditions	Install - 11.2 MVA	$ 3,925
8	Mira Loma 66/12	8481	2025	City of Ontario	Mira Loma 66/12 kV sub is over criteria reserve in 2022 due to the aggressive load growth in the area, and higher SPs caused by new method of cleansing ckts with BESS systems. This area has acres of empty land planned to be developed in the next 10 years.	Mira Loma 66/12 Substation is projected to reach 104% in 2025 under 1-in-10 weather conditions	Install - (3) 28MVA transformers Install - 4.8MVAR cap Install - 2nd 12kV operating bus	$ 3,371
9	Hesperia 115/12	DSP33773	2027	City of Hesperia	New Tapestry housing development in southern Hesperia.	Mesquite 12kV circuit is projected to reach 111% in 2027 under 1-in-10 weather conditions	Install - 28 MVA capacity Install - (2) 4.8 MVAR Capacitor Banks Install - (1) 12 kV Circuit	$ 3,005

(ii) <u>TEGR Forecast</u>

Table II-5 below itemizes the 2 DSP projects, identified through the TEGR forecast, that can be constructed inside the existing perimeter of the substation. These projects are classified as "Substation Modification" in Table II-10 and have been preliminarily reviewed and determined not to require GO 131-D licensing activities. Table II-5 provides a brief scope description and justification for each project with in-service dates within the 2023-2028 GRC period. The total capital expenditures under the TEGR forecast for DSP substations without perimeter expansion with in-service dates within the years 2023 to 2028 is $6.638 million.

Table II-5
TEGR Forecast - 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	Sunnyside 66/12 kV	DSP35818	2026	City of Long Beach	Based on Augmented Forecast studied under TEGR analysis, DCFC and EV MDHD forecasted on circuits out of Sunnyside 66/12.	Sunnyside 66/12 Substation is projected to reach 105% in 2025 and 127% by 2031 under 1-in-10 weather conditions.	Remove 2-20 MVA transformers Install 2-28 MVA transformers	$3,259
2	Mt. Tom 55/12	DSP35812	2027	City of Bishop	Based on Augmented Forecast studied under TEGR analysis, Truck Stop Electrification growth is forecasted on circuits out of Mt. Tom 55/12kV substation.	Mt. Tom 55/12 Substation is projected to reach 112% in 2027 and 169% by 2031 under 1-in-10 weather conditions.	Remove 1-14 MVA transformer Install 1-28 MVA transformer	$3,348

(c) <u>Substations Requiring Perimeter Expansion</u>

The subsections below list the DSP projects, for both the base and TEGR forecasts, where the substation capacity increase requires the existing substation perimeter to be expanded.

(i) <u>Base Forecast</u>

Table II-6 lists the one DSP project, identified through the base forecast, where the substation capacity increase requires the existing substation perimeter to be expanded. The expansion may occur on SCE-owned property or in some cases land must be purchased. The licensing determination and GO 131-D status information for these projects is contained in Section II.D.1.d)(2)(d)(i) in the “Licensing Status of New Substations and Substations Requiring Perimeter Expansions” section of this testimony. The total cost, under the base forecast, for substation projects requiring perimeter expansion is $55.277 million.

Table II-6
Base Forecast – Substation Capacity Projects Requiring Perimeter Expansion
(Total Company – Nominal $000)

Line No.	Substation	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
1	Garnet 115/33	8043	2023	City of Palm Springs	Due to the 180MW+ known cultivation load growth in Desert Hot Springs, Garnet 115/33kV needs to be rebuilt to accomodate more transformation and circuit positions.	Garnet 115/33 Substation is projected to reach 104% in 2025 under 1-in-10 weather conditions	Rebuild- 115kV, 33kV & 12kV switching racks Install - (2) 56MVA transformers Install - (4) 33kV Capacitor Banks	55,277

(ii) <u>TEGR Forecast</u>

There are no projects greater than or equal to $3 million identified through the TEGR forecast, where the substation capacity increase requires the existing substation perimeter to be expanded. The one project less than $3 million is included in the workpapers.

(d) <u>New Substations</u>

The subsections below list the DSP projects, for both the base and TEGR forecasts, for which construction of new substations is required to provide additional capacity to meet needs. Examples of these types of projects include those for which construction of new substations is needed to provide the additional capacity required to meet the electrical needs of the area.

(i) <u>Base Forecast</u>

The projects in Table II-7 below represent new substation projects, identified through the base forecast, which may require licensing activities. The licensing determination and GO 131-D status information for these projects are contained in Table II-7 in the "Construction Licensing under G.O. 131-D" section of this testimony. Based on the base forecast, SCE plans to construct two new substations from 2023 – 2028, which are documented in Table II-7. The forecast for constructing these two new substations is $373.208 million.

Table II-7
Base Forecast - New Substation Projects
(Total Company – Nominal $000)

Line No.	Substation	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
1	Del Valle 66/16	4800	2028	City of Santa Clarita	New mega-tract housing development (approx. 21,000 new homes) with and over 10M square feet of commercial/industrial development in the Santa Clarita area requires an additional distribution substation and associated 66 kV sources lines and 16 kV distribution lines.	Saugus 66/16 Substation is projected to reach 111% in 2029 under 1-in-10 weather conditions Tips 16kV circuit is projected to reach 194% in 2029 under 1-in-10 weather conditions	New Substation	124,281
2	Calcity 115/12	8256	2028	California City	Over 90 new cultivation load service requests in California City, totaling approximately 150 MVA, necessitate rebuilding the existing Cal City 33/12 kV Substation (to 115/33 and 115/12 kV) which cannot serve more than the approximately 20 MVA it currently serves.	Calcity 'A' 33/12 Substation is projected to reach 141% in 2028 under 1-in-10 weather conditions Calcity 'B' 33/12 Substation is projected to reach 491% in 2028 under 1-in-10 weather conditions Greasewood 12kV circuit is projected to reach 171% in 2028 under 1-in-10 weather conditions Overall 12kV circuit is projected to reach 681% in 2028 under 1-in-10 weather conditions	New Substation	248,927

(ii) <u>TEGR Forecast</u>

The table below lists projects, identified through the TEGR forecast, for which construction of new substations is needed to provide the additional capacity required to meet the additional TE-driven electrical needs of the area. Based on the TEGR forecast, SCE plans to construct three additional new substations from 2023 – 2028, which are documented in the table below. These projects may require licensing activities. A preliminary licensing determination and GO 131-D status information for these projects are contained in Table II-10 in the "TEGR Forecast - Construction Licensing under G.O. 131-D" section II.D.1.d)(2)(e) of this testimony below. The forecast for constructing these three new substations is $117.696 million.

Table II-8
TEGR Forecast – New Substation Projects
(Total Company – Nominal $000)

Substation	Project No.	Operating Date	Location	Driver	Forecasted Violation	Project Scope	Total Cost
(TEGR) New 66/12 kV (D) Substation % Hinson System	DSP35829	2028	City of Long Beach	Based on Augmented Forecast studied under TEGR analysis, Port of Long Beach Electrification, Medium/Heavy Duty EV, and Truck Stop (TSE) forecasted on existing substations (Dike 66/12, State Street 66/12, Seabright 66/12, and Pico 66/12) and circuits currently serving the area.	Under 1-in10 weather conditions, circuits and substations serving the Port of Long Beach area are projected to reach: 117% in 2028 and 165% by 2031 at State Street 66/12 Substation 105% in 2023 and 486% by 2031 at Webster 12 kV out of State Street 66/12 substation 100% in 2030 and 111% by 2031 at Baxter 12 kV out of State Street 66/12 Substation 101% in 2028 and 177% by 2031 at Forest 12 kV out of State Street 66/12 Substation 109% in 2029 and 131% by 2031 at Dike 66/12 Substation 105% in 2030 and 110% by 2031 at Dredge 12 kV out of Dike 66/12 Substation 112% in 2030 and 120% by 2031 at the Pico 66/12 Substation 100% in 2028 and 158% by 2031 at Admiral 12 kV out of Pico 66/12 Substation 166% in 2028 and 183% by 2031 at Bow 12 kV out of Pico 66/12 Substation 104% in 2030 and 108% by 2031 at Seaside 12 kV out of Pico 66/12 Substation	Construct new 66/12 substation Install 4-28 MVA transformers Install 4-4.8 MVAR capacitor banks Install 6-12 kV circuits	59,402
(TEGR) New 33/12 kV (D) Substation % Kramer System	DSP35807	2028	City of Barstow	Based on Augmented Forecast studied under TEGR analysis, major Truck Stop Electrification (TSE) forecasted on Judy out of Ordway 33/12.	Ordway 33/12 Substation is projected to reach 155% in 2026 and 334% by 2031 under 1-in-10 weather conditions. Judy 12kV % Ordway is projected to reach 133% in 2026 and 336% by 2031 under 1-in10 weather conditions.	Construct new 33/12 substation Install 2-28 MVA transformers Install 2-4.8 MVAR capacitor banks Install 2-12 kV circuits	29,067
(TEGR) New 33/12 kV (D) Substation % Vista System	DSP35822	2028	City of Bloomington	Based on Augmented Forecast studied under TEGR analysis, Truck Stop Electrification (TSE) Bombay 12 kV and Turntable 12 kV circuits out of Bloomington 66/12 Substation.	Bombay 12kV and Turntable 12 kV % Bloomington 66/12 Substation is projected to reach 130% and 135%, respectively, in 2028 under 1-in-10 weather conditions.	Construct new 33/12 substation Install 2-28 MVA transformers Install 2-4.8 MVAR capacitor banks Install 2-12 kV circuits	29,587

(e) <u>Licensing of New Substations or Substations Requiring Perimeter Expansions</u>

(i) <u>Base Forecast</u>

SCE must comply with the licensing provisions of GO 131-D before constructing electric facilities operating at voltages greater than 50 kV.[80] Table II-9 below contains the licensing and exemption information for each DSP Substation project identified through the base forecast. Besides identifying projects for which Certificate of Public Convenience and Necessity (CPCN)[81] or Permit to Construction (PTC)[82] applications have already been filed under GO 131-D, SCE performed an additional review of the projects in Table II-9. This review aimed to determine: (1) need for a CPCN or PTC application to be filed under GO 131-D, (2) whether a project could qualify for an exemption under GO 131-D, or (3) whether a project was subject to the GO 131-D provisions. The determinations regarding the application and exemption status for the projects in our current load growth plan are provided. Based on these determinations, planned projects fall into four primary categories, which are:

[80] *See* D.94-06-014 and D.95-08-038 (Rules, Procedures and Practices Applicable to Transmission Lines Not Exceeding 200 Kilovolts) Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located in California.

[81] GO 131-D, Section A.

[82] GO 131-D, Section B.

1. Projects for which a CPCN[83] or PTC[84] has already been filed.

2. Projects for which SCE expects a CPCN or PTC to be filed.

3. Projects considered exempt under GO 131-D (e.g., a project involving construction for the minor relocation of existing power lines facilities up to 2,000 in length may qualify for a PTC exemption under GO 131-D, Section III.B.1.c.).

4. Projects known as "substation modification" projects,[85] which are not subject to PTC requirements because they involve construction within an existing substation that does not exceed the substation's previously rated voltage.

Table II-9
Base Forecast - Construction Licensing Under GO 131-D

Line No.	Project No.	Project Name	Operating Date	Licensing Determination
1	8101	Lancaster 66/12 Substation	Jun-23	Substation Modification
2	8043	Garnet 115/33 Substation	Jun-23	Permit to Construct
3	8330	Sun City 115/12 Substation	Jun-23	Substation Modification
4	8388	Hathaway 66/12 Substation	Aug-23	Substation Modification
5	8374	Archibald 66/12 Substation	Dec-23	Substation Modification
6	8386	Roadway 115/12 Substation	Dec-23	Substation Modification
7	8360	Catalina 12/2.4 Substation	Jun-24	Substation Modification
8	DSP35666	North Oaks 66/16 Substation	Jun-25	Substation Modification
9	8481	Mira Loma 66/12 Substation	Jun-25	Substation Modification
10	DSP33773	Hesperia 115/12 Substation	Jun-27	Substation Modification
11	4800	Del Valle 66/16 Substation	Jun-28	Permit to Construct
12	DSP35404	Camden 66/12 Substation	Jun-28	Substation Modification
13	8148	Baker 115/12 Substation	Jun-28	Permit to Construct
14	8256	Cal City 115/12 Substation	Jun-28	Permit to Construct

(ii) <u>TEGR Forecast</u>

Table II-10 below contains a preliminary licensing determination for each of the DSP Substation projects identified in the TEGR forecast.

[83] CPCNs are required for projects involving construction of transmission line facilities operating at 200 kV or greater.

[84] PTCs are required for projects involving construction of subtransmission line facilities operating between 50 kV and 200 kV and substations operating above 50 kV.

[85] GO 131-D, Section B.

Table II-10
TEGR Forecast – Construction Licensing Under GO 131-D

Line No.	Project No.	Project Name	Operating Date	Preliminary Licensing Determination
1	DSP35818	(TEGR) Sunnyside 66/12 kV (D) - Bank Replacement	Jun-26	Substation Modification
6	DSP35811	(TEGR) Fernwood 66/12 (D) - Bank Replacement	Jun-26	Subject to Licensing
7	DSP35784	(TEGR) State Street 66/12 (D) - Disconnect Replacement	Jun-26	Substation Modification
2	DSP35812	(TEGR) Mt. Tom 55/12 (D) - Bank Replacement	Jun-27	Substation Modification
3	DSP35829	(TEGR) New 66/12 kV (D) Substation % Hinson System	Jun-28	Subject to Licensing
4	DSP35807	(TEGR) New 33/12 kV (D) Substation % Kramer System	Jun-28	Subject to Licensing
5	DSP35822	(TEGR) New 33/12 kV (D) Substation % Vista System	Jun-28	Subject to Licensing

2. <u>DER-Driven Grid Reinforcement</u>

DER-Driven Grid Reinforcement capital expenditures upgrade the distribution system to enable the integration of DERs. SCE currently uses profile analysis to identify potential DER-driven violations. In future years, the advanced DER management and optimization capabilities of SCE's Grid Management System (GMS) program will further integrate DERs into operations forecasting, planning, and market operations and are anticipated to influence future DER-driven grid reinforcement program needs.[86]

Due to the uncertainty in the timing and magnitude of these types of projects, the Commission ordered SCE, in the 2021 GRC Track 1 Final Decision, to establish a memorandum account (the DER-DGRPMA) to track and record capital expenditures associated with the DER-Driven Grid Reinforcement Program.[87] SCE's 2022 distribution planning process, however, did not perform a DER-driven needs analysis due to tool development delays.[88] Thus, SCE's 2022 GNA and DDOR filings do not contain any DER-driven needs or projects and the memorandum account was not utilized. SCE continues to develop software tools and processes to support this analysis but continues to face challenges to complete this work in conjunction with annual distribution planning process timelines. To improve the accuracy and speed to produce study results, SCE has prioritized efforts to deploy software tools utilized for these studies.

Given the continued uncertainty in the timing and magnitude of these types of projects, SCE is not including a forecast for DER-Driven Grid Reinforcement capital expenditures in this GRC.

[86] Please refer to SCE-02, Vol. 06, Part II, Grid Management System.

[87] D.21-08-036.

[88] Please refer to SCE-02, Vol. 06, Part II, Engineering & Planning Software Tools for a discussion of the Long-term Planning Tool and System Modeling Tool.

Instead, SCE proposes to keep the DER-DGRPMA open and to record actually incurred costs in that memorandum account for subsequent reasonableness review. The following sub-sections describe five types of potential DER-Driven Grid Reinforcements that SCE considers.

a) <u>DER-driven Distribution Circuit Upgrades Program Description and Need for Program</u>

DER-driven Distribution Circuit Upgrades cover work outside of the substation required to relieve heavily-loaded distribution circuits projected 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 II.C.2. The work includes upgrading cable or conductors, installing new voltage regulators, and installing new automatic reclosers. As more DERs integrate into the system, these projects can be triggered due to facility ratings being exceeded, system voltage outside of our criteria, and inadequate protection on the distribution system due to short circuit current contributions from DERs. As discussed in II.C.2.b), as DER growth increases, these issues can exist outside of traditional peak load conditions.

b) <u>DER-driven New Circuits Program Description and Need for Program</u>

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

c) <u>DER-driven Substation Transformer Upgrades Program Description and Need for Program</u>

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. Projects under the DER-Driven Substation Transformer Upgrades category increase the substation capacity at existing substations. The driver of this type of project is the DER penetration at the 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 the circuits connected to the substation are experiencing reverse power due to DER growth peaking during non-peak hours, this reverse power aggregates at the substation level. The reverse power flows back through the distribution substations and into the higher voltage systems. Just as with traditional load growth-driven programs, when the amount of power flowing through our equipment exceeds planned loading limits, SCE designs a project to help mitigate the problem. A project under this program would follow the same criteria as load growth-driven projects, however, these DER-driven projects address the amount of power flowing through the distribution substation that is being pushed back from the total aggregate reverse power from the distribution circuits.

d) <u>DER-driven Circuit Breaker Upgrades Program Description and Need for Program</u>

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. 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 a fault current, a fault condition must be isolated quickly to restore safe operating conditions of the power system. Substation circuit breakers are the most common devices used to isolate faults and are relied upon to interrupt the highest fault currents experienced on the distribution system. Substation circuit breakers incapable of interrupting expected fault currents are likely to fail when those faults occur. When the short circuit duty levels exceed the fault current rating of the circuit breakers, SCE will plan to upgrade the circuit breaker with a higher fault current rating, capable of safely interrupting the fault on the system.

e) **<u>DER-driven 4 kV Cutovers Program Description and Need for Program</u>**

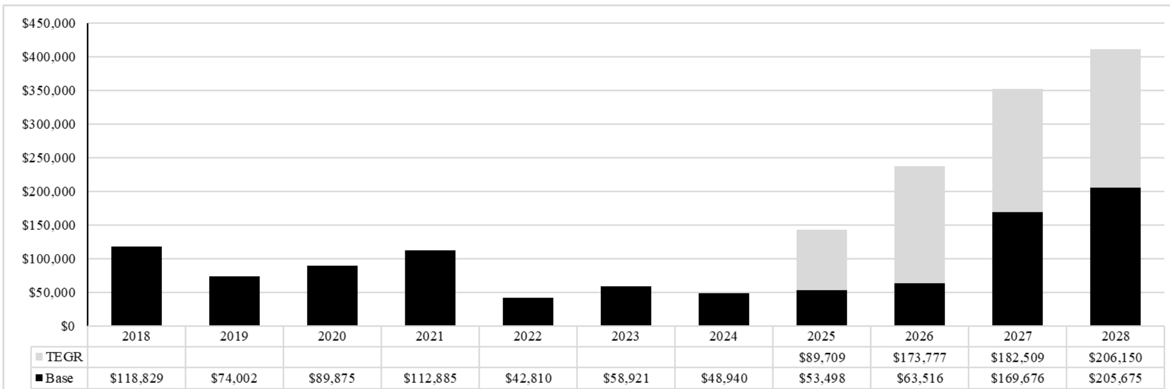
SCE's distribution system is mainly composed of four voltage classes: 4 kV, 12 kV, 16 kV, and 33 kV with increasing DER penetration forecasted at all voltage levels. SCE is especially concerned about the capacity to accommodate DER growth on its 4 kV systems, which typically is SCE's lowest capacity voltage class. DERs interconnected on 4 kV circuits can often result in increased power flows overloading the circuit, and can cause the flow of power to go back to the substation (e.g., reverse power flow) during minimum loading conditions, creating thermal and voltage issues. The result of the reverse power flow can drive the need for a portion of the circuit to be cutover to a higher voltage feeder.

3. **<u>Transmission Substation Plan</u>**

As discussed in Section II.C.4.d), the Transmission Substation Plan (TSP) consists of the Subtransmission Lines Plan, the A-Bank Plan, and the Subtransmission VAR Plan. Each year, SCE develops transmission and distribution system plans that describe the projects and programs required to expand, upgrade, and reconfigure the electrical grid over the next 10 years. Figure II-18 below shows the forecast capital expenditures for the years 2023 to 2028 for the TSP.

Figure II-18
Transmission Substation Plan (TSP) Capital Expenditure Summary[89,90,91]
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)

	Recorded					Forecast					
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base	$118,829	$74,002	$89,875	$112,885	$42,810	$59,051	$49,073	$146,420	$247,977	$360,334	$412,492
TEGR								$89,709	$173,777	$182,509	$206,150
Totals	**$118,829**	**$74,002**	**$89,875**	**$112,885**	**$42,810**	**$59,051**	**$49,073**	**$236,128**	**$421,755**	**$542,843**	**$618,641**



As discussed in section II.C.2.c), the supplemental forecast and additional disaggregation methodologies in the TEGR analysis resulted in additional overloads and project needs to address incremental transportation electrification load aligned with state policies and charting a path to long-term decarbonization. The TEGR analysis reflecting needed projects to meet higher levels of expected TE growth over the 10-year planning horizon identified additional TSP projects including subtransmission lines reconductoring, transformer additions to existing A-Bank substations, and 4 new A-Bank substations. The operating dates of these projects are beyond year 2028 (e.g., beyond the 2023-2028 GRC window) and the total cost of these incremental TSP projects is $4.19 billion. These projects are described in the respective TEGR Forecast sections below. Since these TSP projects are forecast to

89 Refer to WP SCE-02, Vol. 07 Bk. B, pp. 1-57 –Transmission Substation Plan (TSP) Capital Workpaper.

90 An error was identified subsequent to the finalization of financial data. Therefore, the intended financial number that is stated here in testimony does not align with the financial numbers in standardized workpapers and the RO model. Errata will be submitted to align the financial numbers in testimony, standardized workpapers and the RO model at a future date.

91 In the course of finalizing this testimony, SCE identified minor inconsistencies for some projects between the forecast costs listed in system workpapers versus supplemental workpapers. SCE will address those inconsistencies in forthcoming errata.

be placed into service beyond year 2028, their forecast costs are not included in this GRC request. However, although these forecast costs are not included in this GRC request, due to the long-lead time required to construct these projects, SCE will need to initiate planning, designing, siting, and licensing activities during the years 2023 to 2028, particularly for the long-lead time A-Bank substation projects. The 2023 to 2028 forecast costs for these projects are included in the Figure II-18 shown above.

a) Subtransmission Lines Plan

The Subtransmission Lines Plan focuses on SCE's 66 kV and 115 kV subtransmission lines to ensure safe and reliable service to customers. Figure II-19 illustrates how subtransmission lines are connected to SCE's facilities.

Figure II-19
Subtransmission Lines Plan

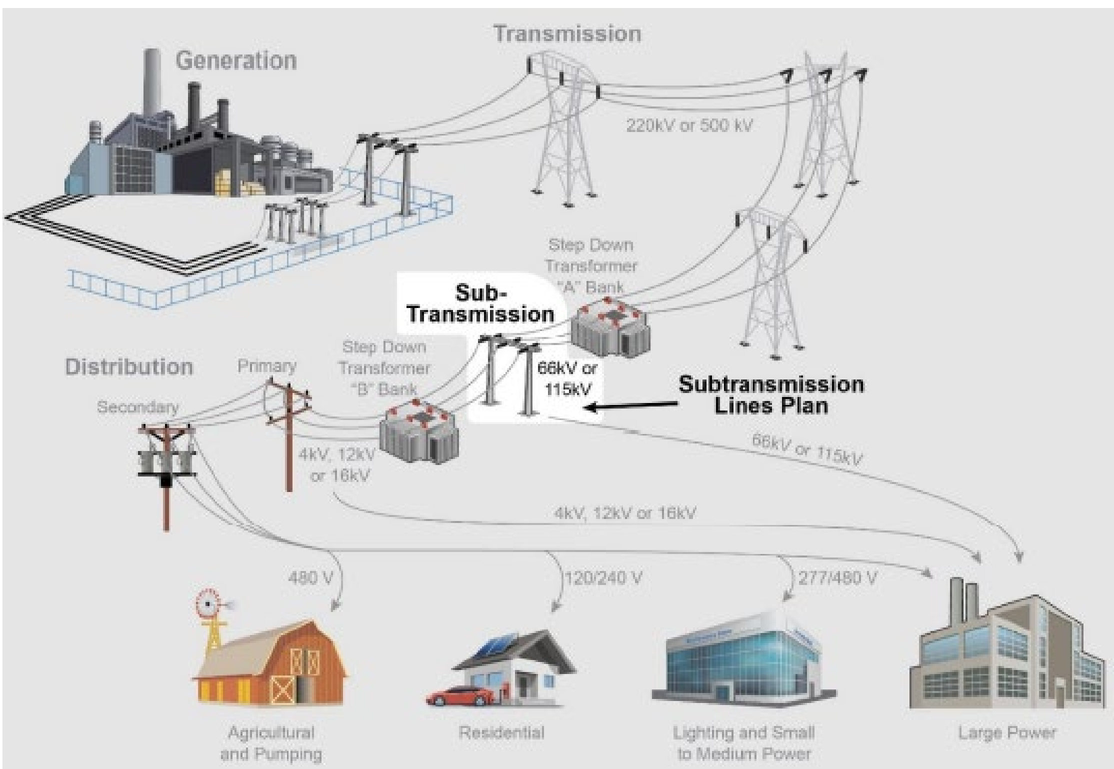


Figure II-20 below provides the total Subtransmission Lines Plan capital forecasts.

Figure II-20
Subtransmission Lines Plan Capital Expenditures Summary
(Total Company – Nominal $000)

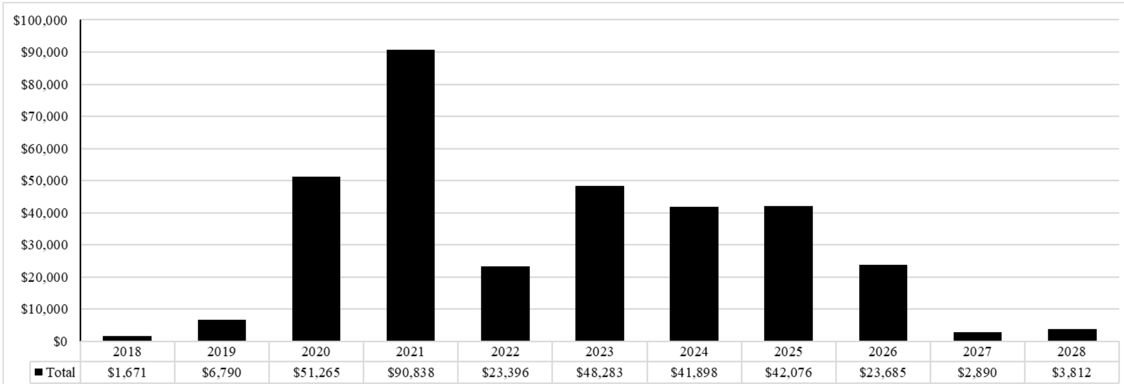


Table II-11
Subtransmission Lines Plan Capital Expenditure Summary[92, 93, 94]
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Operation Date	Prior	2023	2024	2025	2026	2027	2028	Total
1	6030	Valley-Ivyglen 115 kV Subtransmission Line	Jun 2022	186,401	2,651	88	4,398	-	-	-	193,538
2	8252	Saugus - Colossus - Lockheed - Pitchgen 66 kV Subtransmission Line Rebuild	Jun 2023	62	7,439	44	67	115	-	-	7,727
3	8251	Saugus - Newhall No.1 and No.2 66 kV Line Reconductor	Dec 2023	9,202	6,512	-	-	-	-	-	15,714
4	TSP STL35785	Oasis - Palmdale - Quartz Hill 66 kV Subtransmission Line reconductor	Jun 2024	-	1,168	6,228	-	-	-	-	7,396
5	TSP STL35783	Del Sur - Lancaster - Riteaid 66 kV Line Reconductor/Rebuild	Jun 2024	-	1,971	10,747	-	-	-	-	12,718
6	8121	Mesa-Laguna Bell-Narrows 66 kV Subtrans Line Reconductor	Jun 2024	15	3,090	1,796	-	-	-	-	4,902
7	8442	El Nido Load Pocket Multi-Line Outages Mitigation Project	Jun 2024	-	2,300	1,278	-	-	-	-	3,578
8	8403	Reconductor Kramer-Holgate and Holgate leg of Edwards-Holgate-Southbase 115 kV Lines	Jun 2024	314	7,811	3,980	3,487	-	-	-	15,591
9	6055	Mesa-Narrows 66kV Subtransmission Line Reconductor	Jun 2025	11	325	3,396	2,262	-	-	-	5,994
10	8068	Browning-Delano 66 kV Subtransmission Line Reconfiguration	Jun 2025	-	461	1,152	2,995	-	-	-	4,608
11	6698	Elizabeth Lake - Pitchgen 66 kV Subtransmission Line Rebuild	Jun 2026	-	-	114	4,255	1,064	-	-	5,433
12	8509	Saugus - Haskell 66 kV Subtransmission Line Recable	Jun 2026	-	-	675	3,712	2,362	-	-	6,748
13	8425	Santa Clara - Colonia 66 kV Subtransmission Line Rebuild	Jun 2026	-	5,747	6,003	7,068	6,539	-	-	25,357
14	6871	Rector-Riverway No.2 66 kV Subtransmission Line	Jun 2026	-	264	2,379	11,896	11,632	-	-	26,172
15	TSP STL35786	Saugus - North Oaks - Tengen 66 kV Subtransmission Line Recable	Jun 2027	-	1,803	1,843	1,880	1,918	1,957	-	9,400
16	TSP STL35551	Garnet Substation 115 kV Loop	Jun 2028	-	-	-	-	-	879	3,605	4,483
17		Subtotal of Subtransmission Line Plan		196,005	41,541	39,723	42,021	23,630	2,835	3,605	349,360
18		Projects with CPUC jurisdictional cost<$3M		2,630	6,742	2,175	55	55	55	65	11,777
19		Project with operation date outside of GRC window		-	-	-	-	-	-	143	143
20		Total Subtransmission Line Plan		198,635	48,283	41,898	42,076	23,685	2,890	3,812	361,280

(1) <u>Program Description and Need for Program</u>

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

92 Refer to WP SCE-02, Vol. 07 Bk. B, pp. 58-175 – Subtransmission Line Projects.

93 Refer to WP SCE-02, Vol. 07 Bk. B, pp. 176-177 – Subtransmission Line Projects Less Than $3M.

94 Refer to WP SCE-02, Vol. 07 Bk B, pp. 178-179 – Subtransmission Line Projects Outside the GRC Window.

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, 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-19. The Subtransmission Lines Plan includes loop-in projects, reconductoring or recabling projects, new line projects and voltage-driven capacitor projects.

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

SCE's comprehensive Subtransmission Lines Plan includes four different types of projects described in the following sections:

(a) Loop-In or Line Modification Projects

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

A Line Modification project typically involves projects such as subtransmission line rearrangements, opening shields, replacing limiting components, and/or upgrading protection scheme of subtransmission lines. Additionally, this could involve changing a

Preferred/Emergency configuration to a paralleled configuration or installing a new switchrack upon which multiple subtransmission lines can be terminated. The loop-in/Line Modification projects are described in Table II-12 below.

Table II-12
Base Forecast Loop-In or Line Modification Projects
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Project Scope	peration Da	Project Type	Overload	Total Cost
1	TSP STL35784	Oasis 66/12 kV (D) Substation Conductor Upgrade	Oasis 66/12 kV (D) Substation Conductor Upgrade: Replace the substation position conductor on the Palmdale - Quartz Hill Line (Position 1) and the substation operating and transfer bus conductors	Jun 2023	Likely Contingency	109.2% / 2022	$117
2	TSP STL35270	Icegen - Jersey - Nola 66 kV: Open Shields	Icegen - Jersey - Nola 66 kV: Open Shields on the UG section	Jun 2023	Likely Contingency	104.6% / 2022	$106
3	4891	Arrowhead 115/33 kV - Loop Station	Arrowhead 115/33 kV - Loop Station. Reconfigure Arrowhead 115 kV bus. Move Mojave Siphon to existing Arrowhead-Calectric-Devil Canyon-Shandin 115 kV Subtransmission Line.	Dec 2023	Reliability	Reliability No Overload	$2,255
4	8442	El Nido Load Pocket Multi-Line Outages Mitigation Project	El Nido Load Pocket Multi-Line Outages Mitigation Project	Jun 2024	Likely Contingency	Multi Line Outage	$3,578
5	8477	Etiwanda 220/66 Upgrade CB	Etiwanda 220/66 - Upgrade 66 kV CB#61 and #62 to 2000 Amp CB	Jun 2024	Likely Contingency	111.3% / 2022	$769
6	TSP STL35551	Garnet Substation 115 kV Loop	Garnet Substation 115 kV Loop - Loop the Devers-Farrell-Windland 115 kV Line into Garnet substation, creating the new Devers-Garnet-Windland 115 kV Line and new Farrell-Garnet #2 115 kV Line	Jun 2028	Likely Contingency	101.0% / 2028	$4,483
7	8504	Saugus Substation CB Upgrade	Saugus Substation: Upgrade 66 kV 1200 A CB to 2000 A CB 50 kA	Jun 2028	Likely Contingency	102.5% / 2028	$230

(b) <u>Reconductoring and Recabling Projects</u>

As shown in Table II-13, reconductoring or recabling projects are identified to increase the capacity of existing subtransmission lines by replacing existing conductors or cables with higher capacity ones so that the forecast load can be safely and reliably served during both normal conditions and emergency Likely Contingency conditions.

Table II-13
Base Forecast Loop-In or Line Modification Projects
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Project Scope	Operation Date	Project Type	Overload	Total Cost
1	TSP STL35784	Oasis 66/12 kV (D) Substation Conductor Upgrade	Oasis 66/12 kV (D) Substation Conductor Upgrade: Replace the substation position conductor on the Palmdale - Quartz Hill Line (Position 1) and the substation operating and transfer bus conductors	Jun 2023	Likely Contingency	109.2% / 2022	117
2	TSP STL35270	Icegen - Jersey - Nola 66 kV: Open Shields	Icegen - Jersey - Nola 66 kV: Open Shields on the UG section	Jun 2023	Likely Contingency	104.6% / 2022	106
3	4891	Arrowhead 115/33 kV - Loop Station	Arrowhead 115/33 kV - Loop Station. Reconfigure Arrowhead 115 kV bus. Move Mojave Siphon to existing Arrowhead-Calectric-Devil Canyon-Shandin 115 kV Subtransmission Line.	Dec 2023	Reliability	Reliability No Overload	2,255
4	8442	El Nido Load Pocket Multi-Line Outages Mitigation Project	El Nido Load Pocket Multi-Line Outages Mitigation Project	Jun 2024	Likely Contingency	Multi Line Outage	3,578
5	8477	Etiwanda 220/66 Upgrade CB	Etiwanda 220/66 - Upgrade 66 kV CB#61 and #62 to 2000 Amp CB	Jun 2024	Likely Contingency	111.3% / 2022	769
6	TSP STL35551	Garnet Substation 115 kV Loop	Garnet Substation 115 kV Loop - Loop the Devers-Farrell-Windland 115 kV Line into Garnet substation, creating the new Devers-Garnet-Windland 115 kV Line and new Farrell-Garnet #2 115 kV Line	Jun 2028	Likely Contingency	101.0% / 2028	4,483
7	8504	Saugus Substation CB Upgrade	Saugus Substation: Upgrade 66 kV 1200 A CB to 2000 A CB 50 kA	Jun 2028	Likely Contingency	102.5% / 2028	230

(c) <u>New Line Projects</u>

As shown in Table II-14, new line projects are identified when it is not feasible to transfer sufficient load to lower the forecast load of existing subtransmission lines to below their planned loading limits under emergency Likely Contingency conditions.

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

Line No.	Project No.	Project Name	Project Scope	Operation Date	Project Type	Criteria Violation	Total Cost
1	6030	Valley-Ivyglen 115 kV Subtransmission Line	Valley-Ivyglen 115 kV Subtransmission Line: Construct 26 miles of new 115 kV subtransmission line (24 miles OH and 2 miles UG) (Phases 1 and 2)	Jun 2022	Basecase and Likely Contingency	104.4% / 2022	193,538
2	8068	Browning-Delano 66 kV Subtransmission Line Reconfiguration	Browning-Delano 66 kV Subtransmission Line Reconfiguration: Install approx. 2.0 miles of new OH 954 SAC to extend idled Delano-Pandol 66 kV Subtransmission Line into Browning Substation to create the new Browning-Delano 66 kV Subtransmission Line.	Jun 2025	Likely Contingency	0.932 pu / 2022	4,608
3	6871	Rector-Riverway No.2 66 kV Subtransmission Line	Rector-Riverway No.2 66 kV Subtransmission Line: Construct approximately 13 miles of 954 SAC and 0.6 mile of 3000 Cu. of new 66 kV source line.	Jun 2026	Likely Contingency	109.9% / 2022	26,172

(d) <u>Voltage-Driven Projects</u>

There are five subtransmission capacitor projects required to correct greater than 5% voltage drop conditions during emergency Likely Contingency events. These five projects are each under $3 million. The total cost of these projects for the years 2023 to 2028 is $5.918 million.

Table II-15
Voltage-Driven Projects
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Project Scope	Operation Date	Project Type	Criteria Violation	Total Cost
1	TSP STL35557	Neenach 66/12 kV Substation (D) -Install Capacitor Bank	Neenach 66/12 kV Substation (D) - Install 14.4 MVAR capacitor bank to mitigate low voltage violation at Westpac 66/4.16 kV Customer Substation under N-1 loss of Bailey-Neenach-Westpac 66 kV Line (Bailey segment)	Jun 2023	Likely Contingency	66 kV Bus Voltage of 0.915 PU /2022	1,147
2	8156	Thornhill 115/12 kV Install Capacitor Bank	Thornhill 115/12 kV - Install new 14.4 MVAR, 115 kV Capacitor	Jun 2023	Likely Contingency	115 kV Bus voltage of 0.949 PU / 2024	2,065
3	TSP STL35729	Browning 66/12 Substation Install Capacitor Bank	Browning 66/12 Substation (D): Install temporary 14.4 MVAR capacitor bank to mitigate low voltage violations at Browning 66/12 and Quinn 66/12 Substations under N-1 conditions	Jun 2023	Likely Contingency	66 kV Bus Voltage of 0.932 pu / 2022	1,465
4	8253	Edwards 115/33 Install Capacitor Bank	Edwards 115/33 (D): Install a staged 28.8 MVAR, 115 kV capacitor bank (2-14.4 MVAR units)	Jun 2024	Basecase	115 kV Bus Voltage of 0.94 PU / 2022	1,098
5	TSP STL35763	Hi Desert 115 kV Substation Install Capacitor Bank	Hi Desert 115 kV Substation - Install one (1) 14.4 MVAR Capacitor	Jun 2030	Likely Contingency	115 kV Bus Voltage of 0.94 PU / 2030	143

(2) <u>Licensing Status of Subtransmission Lines Projects</u>

Table II-16 below contains the licensing and exemption information for each of the Subtransmission Lines projects. All of these projects were identified from the base forecast.

Table II-16
Licensing and Exemption Status of Subtransmission Line Projects

Line No	Project No.	Project Name	Operation Date	Preliminary Licensing Determination
1	6030	Valley-Ivyglen 115 kV Subtransmission Line	Jun 2022	PTC Granted
2	8252	Saugus - Colossus - Lockheed - Pitchgen 66 kV Subtransmission Line Rebuild	Jun 2023	Exemption B
3	TSP STL35784	Oasis 66/12 kV (D) Substation Conductor Upgrade	Jun 2023	Substation Modification
4	TSP STL35557	Neenach 66/12 kV Substation (D) -Install Capacitor Bank	Jun 2023	Substation Modification
5	TSP STL35270	Icegen - Jersey - Nola 66 kV: Open Shields	Jun 2023	Under Review
6	6652	Saugus-Elizabeth Lake-MWD Foothill 66 kV Subtransmission Line Reconductor	Jun 2023	Exemption G
7	8156	Thornhill 115/12 kV Install Capacitor Bank	Jun 2023	Substation Modification
8	TSP STL35729	Browning 66/12 Substation Install Capacitor Bank	Jun 2023	Substation Modification
9	4891	Arrowhead 115/33 kV - Loop Station	Dec 2023	Exemption B
10	8251	Saugus - Newhall No. 1 and No. 2 66 kV Line Reconductor	Dec 2023	Exemption E
11	TSP STL35785	Oasis - Palmdale - Quartz Hill 66 kV Subtransmission Line reconductor	Jun 2024	GO 131-D Under Review
12	TSP STL35783	Del Sur - Lancaster - Riteaid 66 kV Line Reconductor/Rebuild	Jun 2024	GO 131-D Under Review
13	8121	Mesa-Laguna Bell-Narrows 66 kV Subtrans Line Reconductor	Jun 2024	GO 131-D Under Review
14	8442	El Nido Load Pocket Multi-Line Outages Mitigation Project	Jun 2024	Exemption G
15	8477	Etiwanda 220/66 Upgrade CB	Jun 2024	Substation Modification
16	8403	Reconductor Kramer-Holgate and Holgate leg of Edwards-Holgate-Southbase 115 kV L	Jun 2024	Exemption G
17	8253	Edwards 115/33 Install Capacitor Bank	Jun 2024	Substation Modification
18	6055	Mesa-Narrows 66kV Subtransmission Line Reconductor	Jun 2025	GO 131-D Under Review
19	8068	Browning-Delano 66 kV Subtransmission Line Reconfiguration	Jun 2025	GO 131-D Under Review
20	6698	Elizabeth Lake - Pitchgen 66 kV Subtransmission Line Rebuild	Jun 2026	TBD
21	8509	Saugus - Haskell 66 kV Subtransmission Line Recable	Jun 2026	GO 131-D Under Review
22	8425	Santa Clara - Colonia 66 kV Subtransmission Line Rebuild	Jun 2026	GO131-D Under Review
23	6871	Rector-Riverway No. 2 66 kV Subtransmission Line	Jun 2026	GO 131-D Under Review
24	TSP STL35786	Saugus - North Oaks - Tengen 66 kV Subtransmission Line Recable	Jun 2027	GO 131-D Under Review
25	8504	Saugus Substation CB Upgrade	Jun 2028	GO 131-D Under Review
26	TSP STL35551	Garnet Substation 115 kV Loop	Jun 2028	Under Review
27	TSP STL35763	Hi Desert 115 kV Substation Install Capacitor Bank	Jun 2030	Substation Modification

(3) <u>Basis for Capital Expenditure Forecast</u>

(a) <u>Base Forecast – Subtransmission Line Projects</u>

SCE has identified 16 subtransmission lines projects with costs equal to or greater than $3 million. The total cost for these 16 projects is $145.9 million for the years 2023 to 2028. Additional projects with less than $3 million in CPUC-jurisdictional costs are not discussed here but are included in workpapers for reference. The total cost for all projects is $155.2 million for the years 2023 to 2028. The subtransmission analysis is performed using General Electric's (GE's) Positive Sequence Load Flow (PSLF) software. The analysis leverages distribution substation forecasts based on the aggregation of associated circuit forecasts. The forecast methodology is based on future load projections for each asset. Each asset has its own loading limit (A-Bank, Subtransmission Lines, etc. all have individual loading limits). SCE compares projected loading values to the current loading limit, and if the projected loading exceeds facility loading limits, a project mitigation solution is developed and forecasted. Infrastructure upgrades are based on the forecasted overload and the least cost solution to mitigate the overload.

(b) TEGR Forecast – Subtransmission Line Projects

As discussed in section II.C.2.c), the supplemental forecast and additional disaggregation methodologies in the TEGR analysis resulted in additional overloads and project needs to address incremental transportation electrification load. These needs are incremental to the base load growth forecast and are necessary to accommodate reasonably expected transportation electrification in line with achieving State policies and targets and supporting customer adoption. To support reliability in accommodating this additional forecasted TE load, SCE has identified 70 subtransmission lines projects with a total cost of $428.796 million, all of which are CPUC-jurisdictional. These projects and costs are not included in SCE's 2023-2028 capital expenditures forecast because the operating dates for these projects and the associated costs are after 2028. Additional project details are included in workpapers for reference.

b) A-Bank Plan

The A-Bank Plan focuses on SCE's transmission substation capacity to ensure safe and reliable service to customers. Figure II-21 illustrates the SCE facility that this section of the testimony addresses.

Figure II-21
A Bank Plan

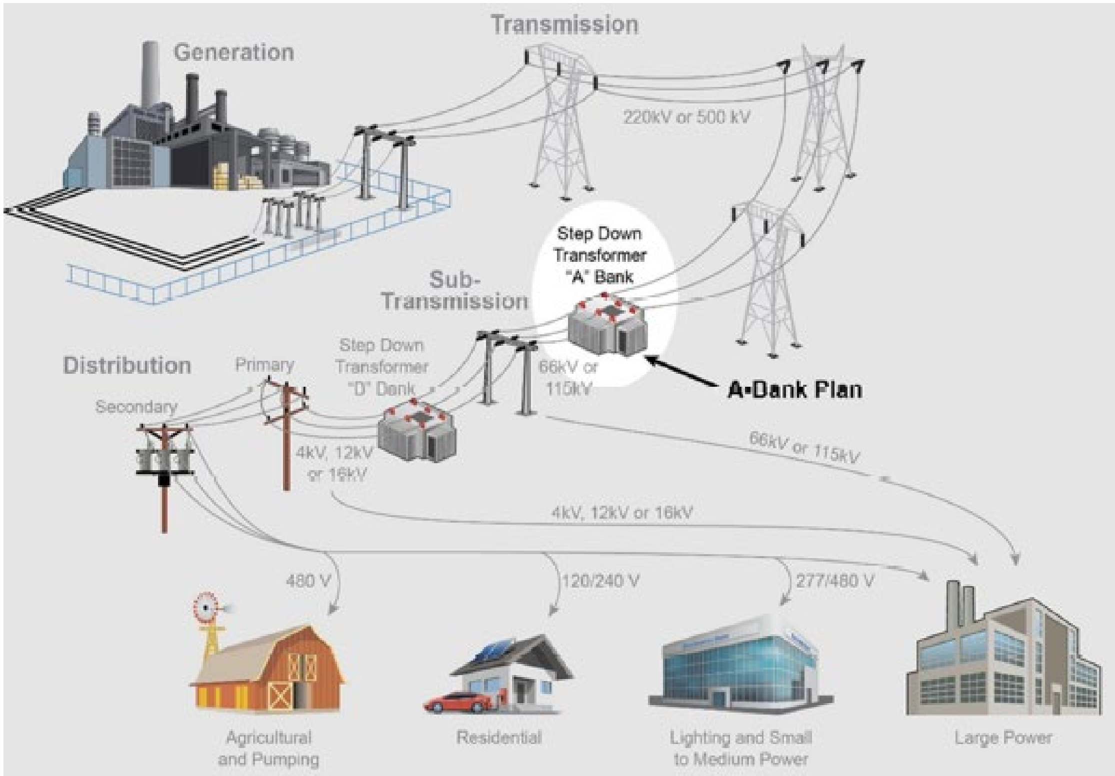
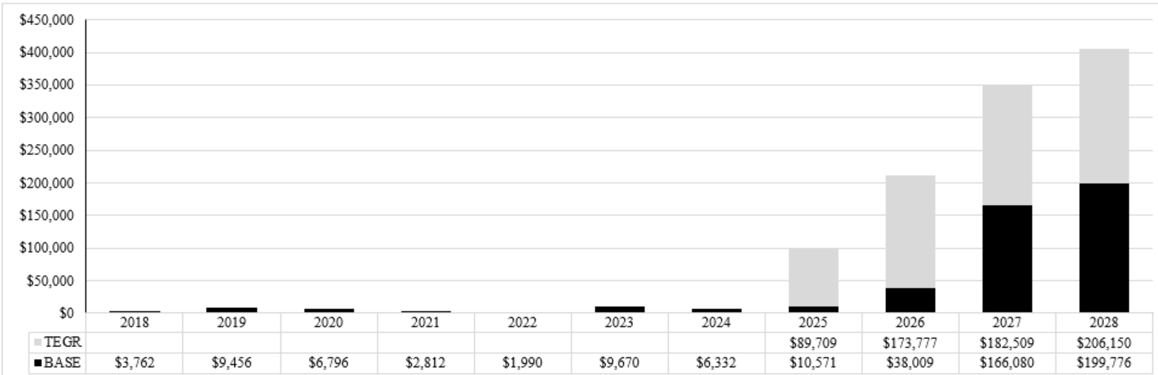


Figure II-22 below provide the A-Bank Plan total SCE capital forecasts.

Figure II-22
A-Bank Plan Capital Expenditure Summary[95,96]
(Total Company – Nominal $000)



Line No.	Project No.	Project Name	Operation Date	Prior	2023	2024	2025	2026	2027	2028	Total
1	7767	Johanna 220/66 (S) Substation - Install new 280 MVA transformer	Jun 2024	22,802	3,600	-	-	-	-	-	26,402
2	TSP ABank35796	Rector 220/66 Substation Split	Jun 2027	-	3,970	4,059	8,298	12,700	10,803	-	39,831
3		Subtotal of A-Bank Plan		22,802	7,570	4,059	8,298	12,700	10,803	-	66,233
4		Projects with CPUC jurisdictional cost<$3M		-	-	-	-	-	-	-	-
5		Project with operation date outside of GRC window		47,351	2,100	2,273	91,981	199,086	337,786	405,926	1,086,503
6		Total A-Bank Plan		70,153	9,670	6,332	100,280	211,786	348,589	405,926	1,152,736

(1) <u>Program Description and Need for Program</u>

The objective of the A-Bank plan is providing adequate capacity at each transmission substation to serve forecast peak loads under normal conditions. These forecast loads represent the maximum demand for the highest expected temperature within a 5-year period, referred to as a one-in-five (1-in-5) year heat storm condition. SCE's planning criteria require a thorough review of SCE's facilities and the impact of peak demands under both normal conditions with all facilities in service, and emergency conditions, referred to as Likely Contingency conditions, when critical equipment is out of service.

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

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[95] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 180-209 –A-Bank Projects.

[96] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 210-211 –A-Bank Projects Outside the GRC Window.

circuit breakers, and installing new A-substations. Table II-17 contains information about A-Bank Substation Capacity Projects identified in the base and TEGR forecasts.

Table II-17
A-Bank Substation Capacity Projects
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Project Scope	Operation Date	Project Type	Overload	Total Cost
1	7767	Johanna 220/66 (S) Substation - Install new 280 MVA transformer	Johanna 220/66 (S) Substation - Install new 280 MVA transformer to mitigate A-bank N-1 condition	Jun 2024	Likely Contingency	102.4% / 2022	$26,402
2	TSP ABank35796	Rector 220/66 Substation Split	Rector 220/66 Substation Split: Rebuild the Rector 66 kV switchrack to be split and upgrade system downstream	Jun 2027	Basecase and Likely Contingency	101.1% / 2022	$39,831
3	6092	Alberhill 500/115 Construct New Substation	Alberhill 500/115 - Construct new 500/115 kV, 1120 MVA substation and associated transmission and subtransmission lines. Add 46.8 MVAR of capacitors. (TSP ABank)	Jun 2029	Basecase and Likely Contingency	122.9% / 2022	$421,434
4	8485	Mira Loma 220/66 kV Substation Upgrade and Split System	Mira Loma 220/66 kV: Add a 4th A-Bank, Split the System, Add a 28.8 MVAR Capacitor Bank, Reconfigure existing Mira Loma-Corona-Pedley 66 kV line, and install a new 66 kV Line segment (3.3 mi UG of 3000 Cu and 2.3 mi OH 954 SAC) to create Mira Loma-Corona No.2. Reconfigure Archibald-Chino-Corona 66kV line and install a new 66 kV Line segment (2.5 mi UG of 3000 Cu) to create Mira Loma 'A'-Chino-Corona 66 kV Line	Jun 2030	Basecase	100.4% / 2030	$12,924
5	TSP ABank35832	(TEGR) IPP New Hinson 220/66 (S) - Construct New 220/66 kV Substation	Construct new 220/66 kV substation and associated transmission and subtransmission lines	Jun 2031	Basecase	332% / 2031	$167,345
6	TSP ABank35846	(TEGR) IPP New Rector 220/66 (S) - Construct New 220/66 kV Substation	Construct new 220/66 kV substation and associated transmission and subtransmission lines	Jun 2031	Basecase	112% / 2031	$59,874
7	TSP ABank35847	(TEGR) IPP New Santiago 220/66 (S) - Construct New 220/66 kV Substation	Construct new 220/66 kV substation and associated transmission and subtransmission lines	Jun 2031	Basecase	124% / 2031	$257,339
8	TSP ABank35848	(TEGR) IPP New Saugus 220/66 (S) - Construct New 220/66 kV Substation	Construct new 220/66 kV substation and associated transmission and subtransmission lines	Jun 2031	Basecase	105% / 2031	$51,277
9	TSP ABank35841	(TEGR) Etiwanda 220/66 kV: Add a 4th A-Bank, Split the System	Etiwanda 220/66 Substation Split: Install new 280 MVA transformer, split and upgrade system downstream	Jun 2031	Basecase	105% / 2031	$29,077
10	TSP ABank35852	(TEGR) Hinson 220/66kV: 4th A-Bank and System Split	Hinson 220/66 Substation Split: Install new 280 MVA transformer, split and upgrade system downstream	Jun 2031	Basecase	342% / 2031	$29,077
11	TSP ABank35855	(TEGR) Lighthipe 220/66kV: 4th A-Bank and System Split	Lighthipe 220/66 Substation Split: Install new 280 MVA transformer, split and upgrade system downstream	Jun 2031	Basecase	126% / 2031	$29,077
12	TSP ABank35856	(TEGR) Santa Clara 220/66kV: 4th A-Bank and System Split	Santa Clara 220/66 Substation Split: Install new 280 MVA transformer, split and upgrade system	Jun 2031	Likely Contingency	124% / 2031	$29,077

(2) <u>Licensing for A-Bank Projects</u>

Table II-18 below contains the licensing and exemption information for each A-Bank Plan project identified in the base and TEGR forecasts.

Table II-18
Licensing and Exemption Status of A-Bank Plan Projects

Line No.	Project No.	Project Name	Operation Date	Preliminary Licensing Determination
1	7767	Johanna 220/66 (S) Substation - Install new 280 MVA transformer	Jun 2024	Substation Modification
2	TSP ABank35796	Rector 220/66 Substation Split	Jun 2027	GO 131-D Under Review
3	6092	Alberhill 500/115 Construct New Substation	Jun 2029	Under Review
4	8485	Mira Loma 220/66 kV Substation Upgrade and Split System	Jun 2030	GO 131-D Under Review
5	TSP ABank35832	(TEGR) IPP New Hinson 220/66 (S) - Construct New 220/66 kV Substation	Jun 2031	Licensing expected
6	TSP ABank35846	(TEGR) IPP New Rector 220/66 (S) - Construct New 220/66 kV Substation	Jun 2031	Licensing expected
7	TSP ABank35847	(TEGR) IPP New Santiago 220/66 (S) - Construct New 220/66 kV Substation	Jun 2031	Licensing expected
8	TSP ABank35848	(TEGR) IPP New Saugus 220/66 (S) - Construct New 220/ 66kV Substation	Jun 2031	Licensing expected
9	TSP ABank35841	(TEGR) Etiwanda 220/66 kV: Add a 4th A-Bank, Split the System	Jun 2031	Under Review
10	TSP ABank35852	(TEGR) Hinson 220/66kV: 4th A-Bank and System Split	Jun 2031	Under Review
11	TSP ABank35855	(TEGR) Lighthipe 220/66kV: 4th A-Bank and System Split	Jun 2031	Under Review
12	TSP ABank35856	(TEGR) Santa Clara 220/66kV: 4th A-Bank and System Split	Jun 2031	Under Review

(3) Basis for Capital Expenditure Forecast

(a) Base Forecast – A-Bank Projects

SCE has identified four A-Bank projects with costs equal to or greater than $3 million. The total cost for these four projects is $430.438 million for the years 2023 to 2028 (all CPUC-jurisdictional). The analysis performed relies on the forecast of the distribution and customer-owned infrastructure associated with the A-Bank. The aggregated load is compared to the individual asset's load limit. When the projected load exceeds the load limit, a least-cost solution will be proposed to mitigate the overload. The projected load and infrastructure upgrade are reevaluated and validated each year as the future load and DER landscape changes each year.

(b) TEGR Forecast – A-Bank Projects

As discussed in section II.C.2.c), the supplemental forecast and additional disaggregation methodologies in the TEGR analysis resulted in additional overloads and project needs to address incremental transportation electrification load. These needs are incremental to the base load growth forecast and are necessary to accommodate reasonably expected transportation electrification in line with serving customers and achieving state policies and targets. To support reliability in accommodating this additional identified TE load, SCE has identified eight A-Bank projects (four new A-Bank substations and four transformer additions to existing A-bank substations) with a total cost of $3.74 billion. While the operating dates of these projects are beyond the 2023-2028 GRC window, initial costs through 2028 are $652.145 million. Since these A-Bank projects are projected to be placed into service beyond year 2028, their projected costs are not included in this GRC request. Additional project details are included in the workpapers for reference.

While operating dates of these A-Bank projects are outside the GRC window, it is important to note the increasing future scale of the projects and associated long lead times to implement. A-Bank substation projects can take over 10 years to fully implement from design and licensing to construction and operational use. Preparatory work such as planning, designing, siting, and licensing will need to begin within the 2023-2028 GRC cycle so that the projects are able to be completed and ready in time to serve the TE-driven customer load that is coming. Proactive planning for these long lead time projects is paramount to provide a measure of certainty for customers and enable customers' EV adoption and market transformation while maintaining grid reliability. Otherwise, a reactive approach that defers grid infrastructure requirements risks SCE being unable to feasibly construct in a timely manner, delaying customer adoption, and disrupting the market, which is particularly salient to commercial fleet operations regulated to comply under the zero-emission fleet requirements of the CARB Advanced Clean Fleet rule. Given the long lead times to implement, deferring consideration of these projects to the future can ultimately put achieving the State's decarbonization policy objectives at risk.

c) Subtransmission VAR Plan

The Subtransmission VAR Plan focuses on SCE's system reactive power needed to ensure safe and reliable service to customers.

Table II-19
Subtransmission VAR Capital Expenditure Summary[97,98]
(Total Company – Nominal $000)

Line No.	Operation Date	Prior	2023	2024	2025	2026	2027	2028	Total
1	Subtotal of Subtransmission VAR Plan	0	0	0	0	0	0	0	0
2	Projects with CPUC jurisdictional cost<$3M	0	968	709	851	1823	326	0	4678
3	Project with operation date outside of GRC window	0	0	0	0	0	379	2087	2467
4	Total Subtransmission VAR Plan	0	968	709	851	1823	706	2087	7145

(1) Program Description and Need for Program

Capacitor banks are installed throughout SCE's system to supply needed reactive power and help maintain adequate voltage. SCE reviews requirements for 66 kV and 115 kV substation capacitor banks over a 10-year planning horizon. Without a comprehensive Subtransmission VAR Plan, SCE would risk reactive power deficiency on the subtransmission system as the peak

97 Refer to WP SCE-02 Vol. 07 Bk. B, pp. 212-213 – Subtransmission VAR Projects Less than $3M.

98 Refer to WP SCE-02 Vol. 07 Bk. B, pp. 214-215 – Subtransmission VAR Projects Outside the GRC Window.

demand for electricity continues to increase in our service territory. Inadequate subtransmission reactive power supply could compromise SCE's ability to provide adequate voltage to end-use customers and, in a worst-case scenario, result in cascading outages and widespread blackouts after disturbances on the high-voltage transmission grid.

(2) Licensing for Subtransmission VAR Projects

Table II-20 below contains the licensing and exemption information for each Subtransmission VAR project.

Table II-20
Licensing for Subtransmission VAR Projects

Line No.	Project No.	Project Name	Operation Date	Preliminary Licensing Determination
1	8466	Universal 66/12 kV Substation Temporary Capacitor Removal	Dec 2023	Substation Modification
2	8507	Etiwanda 220/66 - Install Capacitor Bank	Jun 2024	Substation Modification
3	TSP STV35570	Devers 220/115 kV Substation Install Capacitor Bank	Jun 2026	Substation Modification
4	8438	Channel Island 66/16 kV - Install CapacitorBank	Jun 2027	Substation Modification
5	TSP STV33984	Mira Loma 220/66 kV Install Capacitor Bank	Jun 2029	Substation Modification

(3) Basis for Capital Expenditure Forecast

Table II-21
Subtransmission VAR Projects Capital Expenditures
(Total Company – Nominal $000)

Line No.	Project No.	Project Name	Project Scope	Operation Date	Project Type	Criteria Violation	Total Cost
1	8466	Universal 66/12 kV Substation Temporary Capacitor Removal	Universal 66/12 kV Substation: Removal of Temporary 28.8MVAR Capacitor	Dec 2023	N/A	N/A	114
2	8507	Etiwanda 220/66 - Install Capacitor Bank	Etiwanda 220/66 kV - Install one (1) 28.8 MVAR capacitor on the Etiwanda 66 kV bus	Jun 2024	Basecase	Var Reserve Violation / 2022	1,412
3	TSP STV35570	Devers 220/115 kV Substation Install Capacitor Bank	Devers 220/115 kV Substation: Install one (1) 28.8 MVAR 115 kV Capacitor	Jun 2026	Basecase	VAR Reserve Violation / 2026	1,555
4	8438	Channel Island 66/16 kV - Install CapacitorBank	Channel Island 66/16 kV - Install a 2 stage 66 kV, 28.8 MVAR capacitor (2 stages of 14.4 MVAR)	Jun 2027	Basecase	Var Deficit / 2027	1,597
5	TSP STV33984	Mira Loma 220/66 kV Install Capacitor Bank	Mira Loma 220/66 kV - Install a 28.8 MVAR capacitor bank to mitigate VAR deficit beginning in 2029.	Jun 2029	Basecase	VAR Reserve Violation / 2025	2,467

(a) Base Forecast – Subtransmission VAR Projects

SCE has identified 5 Subtransmission VAR projects with a total cost of $7.145 million for the years 2023 to 2028. All projects are less than $3 million and are subject to CPUC jurisdiction. All projects are detailed in workpapers for reference. Subtransmission VAR projects are identified in conjunction with A-Bank and subtransmission lines analysis. When transformers are upgraded an associated increase in capacitors to balance VARs is proposed. When subtransmission lines are assessed and the increase in load reduces voltage below design standards, the installation of capacitors is also proposed. The need for new capacitor banks is assessed each year to determine if new capacitor projects are needed and the capacitor projects identified previously are still required.

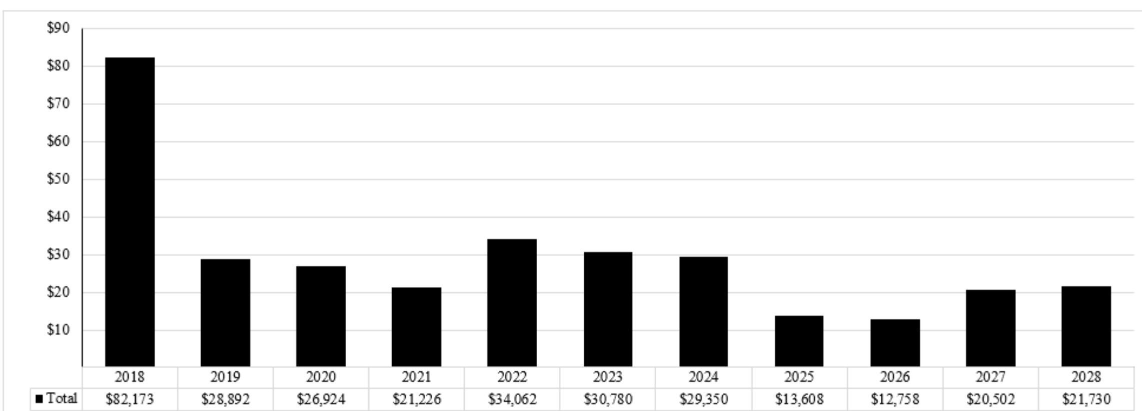
There were no incremental subtransmission VAR projects identified through the TEGR analysis.

4. System Improvement Programs

a) Distribution Plant Betterment

Figure II-23 below shows recorded costs for the years 2018 to 2022 and the forecast capital expenditures for the years 2023 to 2028 for the Distribution Plant Betterment program. 2018 recorded expenditures were higher than the recorded expenditures for the years 2019 to 2022 primarily due to SCE's decision to reduce or defer certain non-wildfire-related activities and programs in order to prioritize emergent public safety risks pertaining to wildfire-related events.

Figure II-23
Distribution Plant Betterment Capital Expenditure Summary [99,100]
WBS Element CET-PD-GPBMTE, CET-PD-LGPBMTW
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



(1) Program Description and Need for Program

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 low voltage problems, new protection devices and

99 Refer to WP SCE-02, Vol. 07 Bk. B, pp. 216-218 – Capital Detail by WBS Element for Distribution Plant Betterment.

100 2018 recorded amounts include $27.654 million for Covered Conductor and $1.027 million for Tree Attachment Remediation that were recorded to Plant Betterment before WCCP accounting structure was created.

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. Additional analysis on the impact of increasing temperature due to climate change was performed and is included in the infrastructure upgrades of the Plant Betterment program.

One example of plant betterment work is facilities required to help ensure SCE is able to meets its obligation of providing adequate voltage within allowable ranges as prescribed by SCE's Commission-approved Rule 2.[101] In some areas, customer load additions or changes in distribution system configurations may lead to voltage violations and must be resolved quickly. Installing voltage regulators, capacitors, or increasing the size of existing overhead conductors or underground cables are typical solutions to remedy voltage issues.

Another example of plant betterment work includes distribution circuit modifications that may be necessary for reliability, safety, or protection reasons. The distribution system is dynamic and changes to it can occur frequently and quickly to meet the electrical needs of customers. Over time and due to these changes, distribution circuits may require additional facilities to be installed (e.g., switches, protective devices, etc.) to help ensure reliable and safe electrical service, along with providing system operational flexibility. For example, to minimize the number of customers that may be impacted when performing routine system maintenance, strategically located switches to sectionalize and transfer load are required. Additionally, to minimize both magnitude (number of customers impacted) and duration of unplanned outages, automatic reclosers[102] are also required in strategic locations. Sometimes, particularly on longer distribution circuits and as circuit configurations change or customer loads change, the locations of existing automatic reclosers are insufficient to perform the needed functions. In these cases, SCE may install additional automatic reclosers. In other cases, customer loads change such that installation of new or upgraded devices becomes required.

A third example of a plant betterment addition is modification of a distribution circuit to allow for the transfer of load from one circuit to an adjacent circuit where the current configuration of the circuitry would not allow it. As identified above, SCE's distribution system consists of a three-phase power system that provides electricity to customers through either three-phase or single-phase service. The distribution circuits that deliver this power are configured as either three

[101] D.97-10-087.

[102] 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.

wire circuits or four-wire circuits. Three-wire circuits have three conductors only, one for each of the three phases. Four-wire circuits have four conductors, one for each of the three phases and a fourth for a neutral path. When single-phase service is required, it can be provided in either of two configurations: (a) "phase-to-phase" or (b) "phase-to-ground." Both configurations provide single-phase service to the customer, however, the electrical connections to provide service are different and the voltage ratings of the transformers providing the service are different.

When SCE identifies a load transfer from one circuit to another as the preferred solution to addressing a projected loading issue, the two circuits must be compatible in their configuration to perform the transfer (e.g., both four-wire circuits or both three-wire circuits). Should the two circuits not have compatible configurations,[103] the addition of a fourth wire is considered to make the circuit configurations compatible. The addition of a fourth wire to an existing three-wire circuit can often be a cost-effective alternative solution to other distribution circuit upgrades or new distribution circuits.

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

(2) Basis for Capital Expenditure Forecast

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

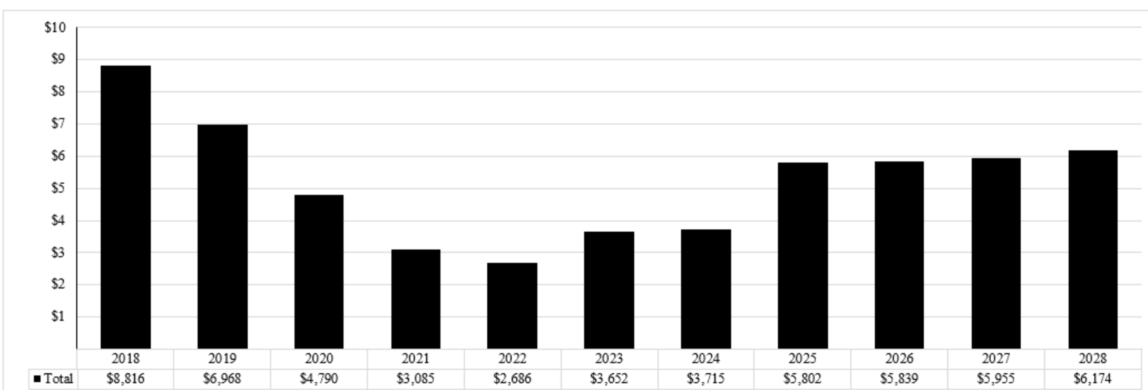
[103] Single-phase "phase-to-ground" connected load requires one phase conductor and a ground conductor (also known as a "fourth wire") and is served by four-wire circuits. This load cannot be transferred to a three-wire circuit as it does not have a "fourth wire" or ground conductor necessary to provide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

shows recorded costs for the years 2018 to 2022 and forecast costs for the years 2023 to 2028 for the Distribution Plant Betterment program. As indicated above, recorded expenditures for the years 2019 to 2022 were lower than previously forecast in the 2021 GRC due to SCE's decision to reduce or defer certain non-wildfire-related activities and programs in order to prioritize emergent public safety risks pertaining to wildfire-related events. As a result, the recorded expenditures for the years 2019 to 2022 yielded a significantly lower than normal average historical cost. Thus, the forecast for this GRC was determined using the same 2015 to 2019 average historical cost used in the 2018 GRC as that more closely represents the volume and cost of projects to address the purpose of the program. The forecasted request for the years 2023 to 2028 is a total of $128.727 million.[104]

b) <u>New Capacitors</u>

Figure II-24 below shows the recorded costs for the years 2018 to 2022 and the forecast capital expenditures for the years 2023 to 2028 for New Capacitors.

Figure II-24
New Capacitors Capital Expenditures Summary[105]
WBS Element CET-PD-LG-NCMTW
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



(1) <u>Program Description and Need for Program</u>

Reactive power demand increases as load continues to increase on the system. Distribution capacitor banks supply reactive power (Volt-Amps Reactive, "VAR") to the

[104] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 219-220 – Distribution Plant Betterment Forecast Methodology.

[105] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 221-222 – Capital Detail by WBS Element for New Capacitors.

distribution system to maintain acceptable power factor and help maintain suitable voltage to serve customers. The program plans installation of new capacitors on distribution circuits that have a reactive power (VAR) deficit.

(2) Basis for Capital Expenditure Forecast

SCE's forecast expenditures for the years 2023 to 2028, as shown in Figure II-24, are based on estimated growth in VAR demand of each circuit on SCE's distribution system and the corresponding numbers of capacitor banks that need to be installed to meet this VAR demand. The VAR demand is calculated based on SCE's peak load forecast and historical load characteristics of each distribution circuit.[106] The capacitor bank cost is inclusive of all capital to complete an installation as it is based on an average of historical closed work orders for completed capacitor installation projects.

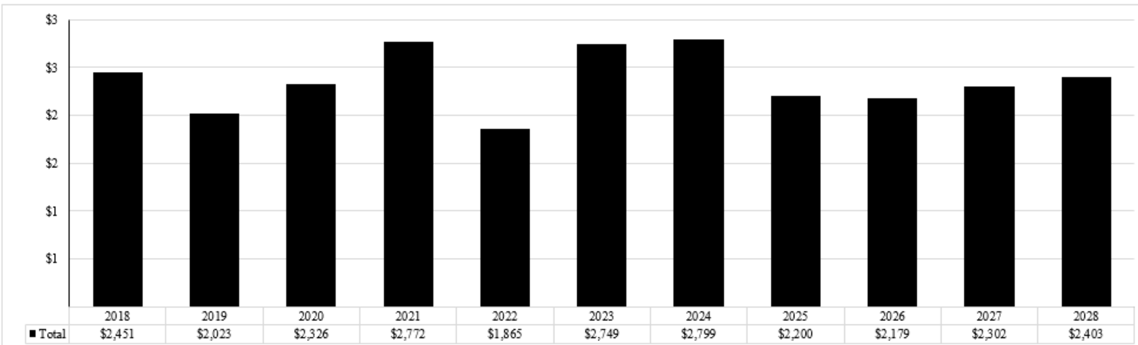
In addition to meeting estimated growth in VAR demand, SCE's forecast expenditures also include installing capacitors to address existing VAR deficit, such as on 33 kV circuits. SCE was not able to completely meet VAR needs of these circuits in previous years due to the unavailability of 33 kV rated capacitor banks, which have been in pilot stages for several years. However, the 33 kV capacitors were released from pilot stages and deployed for installation in 2022. SCE's forecast in this GRC includes the increased cost of these 33 kV capacitors. The total program forecast for the years 2023 to 2028 is $31.136 million.

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

Figure II-25 below shows the recorded cost for the years 2018 to 2022 and forecast capital expenditure for the years 2023 to 2028.

[106] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 221-222 – Capital Detail by WBS Element for New Capacitors.

Figure II-25
Distribution Volt-Var Control (DVVC) and Programmable Capacitor Controller Replacement Program Capital Expenditures Summary[107]
WBS Element CET-PD-GM-CCMTW
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



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(1) <u>Program Description and Need for Program</u>

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 Regulation[108] (CVR) to decrease energy consumption, while maintaining reliable voltage delivery[109] 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 system. A capacitor control's basic function is to provide remote capability[110] to open or close switches on capacitor banks based on established engineering settings for voltage, temperature, and/or time bias control strategies. PCCs are an important asset to the implementation of CVR and play an integral part for the DVVC algorithm. SCE's PCC Replacement program replaces failed or non-functional PCCs and

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[107] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 223-224 – Capital Detail by WBS Element for Distribution Volt-Var Control (DVVC) and Programmable Capacitor Controller Replacement Program.

[108] 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.

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

[110] 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.

upgrades obsolete PCCs in support of the DVVC algorithm. PCCs are also used for automating existing installed capacitor banks[111] to provide additional telemetry capability as well as reliability to the system.

The DVVC program is implemented at SCE as a centralized control algorithm designed to achieve an optimal voltage and VARs across all circuits fed by substation transformers. As shown in Figure II-26 below, supervisory-controlled distribution substation capacitors and existing standard automated distribution field capacitors on distribution circuits are leveraged to provide input for the DVVC algorithm to make real-time decisions by switching on or off the above-mentioned field and substation capacitors. As a result of the optimization, the system average voltage is reduced, which in turn reduces energy consumption while maintaining overall customer service voltage requirements.[112] Since SCE's DVVC program began in 2016, SCE has, as of 2022, successfully implemented the DVVC algorithm to 346 substations. As a result of the DVVC algorithm implementation, SCE has demonstrated that this centralized control strategy resulted in a CVR of 1.07 (0.6% in energy reduction and 0.56% voltage reduction) in 2016 and 2017, and 1.33 (0.8% energy reduction and 0.6% voltage reduction) in 2018.[113] As the CVR program evolves, the need for continued improvement and expansion of the current algorithm to the rest the substations across service territory will further improve CVR benefits.

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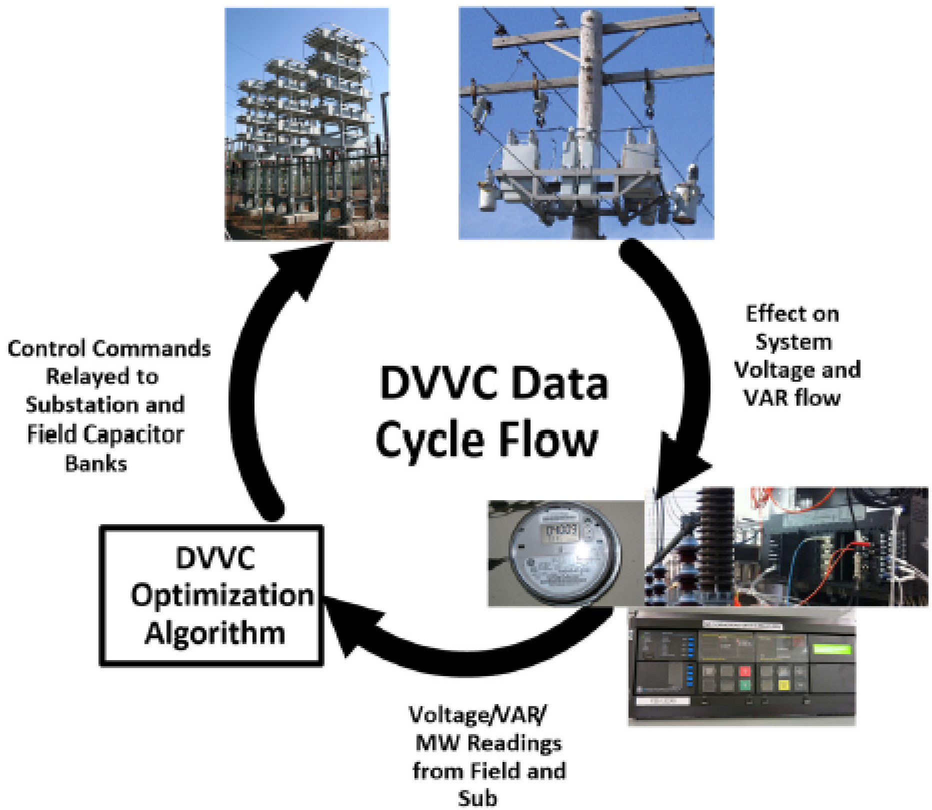
[111] Existing installed capacitor banks that do not have remote control capability are often called "fixed capacitor banks."

[112] 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.

[113] The CVR analysis has not been reperformed since 2018 as SCE has been incorporating improvements to the Load Tap Changer (LTC) and Voltage Regulators for distribution substations with an anticipated completion in 2023.

Figure II-26
DVVC Optimization Process



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(2) Basis for Capital Expenditure Forecast

SCE's PCC replacement forecast is based on recorded replacement costs from 2018–2022. The DVVC algorithm, put in place prior to 2018, provides visibility to the number of failed or non-functioning PCCs and the need to upgrade obsolete PCCs. Historical recorded replacement rates and costs are used to derive the PCC replacement forecast and unit cost.

Figure II-25 above shows the capital expenditure forecast for the DVVC and PCC replacement program for the years 2023 to 2028. The total cost of the DVVC program for years 2023 to 2028 is $14.631 million. SCE expects on average to replace 374 PCCs annually from 2023 to 2028 at an average cost of $6,390[114] (nominal dollars) each.

[114] Average cost was derived using recorded unit cost from 2018–2022.

In 2024, DVVC will be integrated into SCE's Advanced Distribution Management System (ADMS).[115] This will allow the DVVC algorithm to be implemented across the majority of SCE's distribution substations and sub-transmission facilities with the following traits:

- Forecast to have substantial distributed generation penetration
- Possessing the most modern substation automation capabilities
- Areas that have radio network capacity
- 33 kV substations that have voltage and VAR support apparatus with deployment of 33 kV automated capacitors

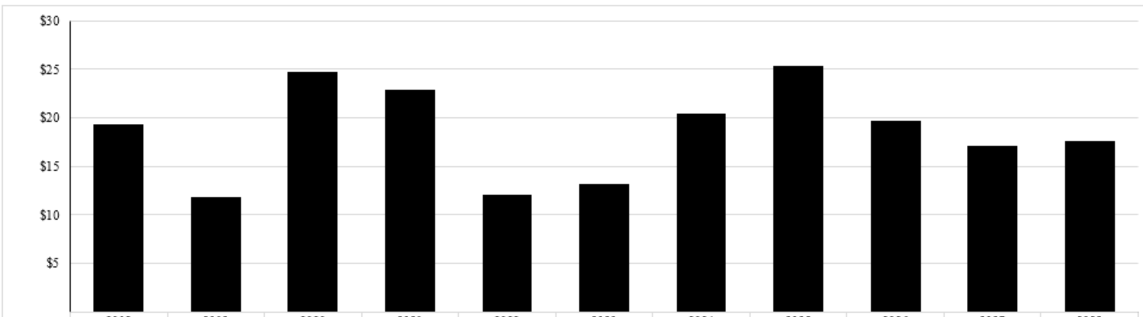
SCE's CVR program will continue to improve the already-implemented DVVC algorithm systems, as well as expanding to stations with active voltage regulation such as Load Tap Changers (LTC), Voltage Regulators, newly automated distribution substations, and newly installed distribution substations. The CVR 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 CVR benefits while collecting and refining LTCs and voltage regulator settings as well as prepare for implementation of DVVC algorithm into advanced solutions such as into SCE's ADMS. Prior to commissioning DVVC for a substation, all settings for transformer LTCs, as well as line and field voltage regulators settings, must be collected for engineering analysis. If the collected settings need to be updated, an SCE Substation Construction & Maintenance technician must update these settings to ensure cohesiveness of the transformer LTCs and voltage regulators to ensure the operation aligns 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's Power System Control (PSC) group updates the DVVC algorithm accordingly in SCE's Distribution Management System (DMS) and Energy Management System (EMS) to reflect the actual locations of station and field capacitors.

[115] Refer to SCE-02 Vol. 06 for more details. Previously the DVVC program was expected to be incorporated in the ADMS system by 2021.

d) <u>Substation Equipment Replacement Program (SERP)</u>

Figure II-27 below shows the recorded costs for the years 2018 to 2022 and the forecast capital expenditures for the years 2023 to 2028 for the Substation Equipment Replacement Program (SERP).

Figure II-27
Substation Equipment Replacement Program (SERP) Capital Expenditures Summary[116]
WBS Element CET-ET-LGSU-408798
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
■ Total	$19,378	$11,806	$24,781	$22,908	$12,119	$13,163	$20,407	$25,360	$19,655	$17,093	$17,553

(1) <u>Program Description</u>

The SERP replaces substation equipment identified to exceed their protection ratings to interrupt fault current (e.g., overstress breaker condition). SCE identifies overstressed substation circuit breakers by comparing each circuit breaker's short circuit duty rating with the potential fault current that circuit breaker will have to interrupt. Overstressed circuit breakers attempting to interrupt fault current that exceed ratings have the potential to cause catastrophic failure resulting in prolonged outages. Leaving these overstressed circuit breakers in service can jeopardize worker safety if a catastrophic failure were to occur when work is being performed in the substation. When SCE has identified these conditions in the past, an operating bulletin or procedure restricting personnel access into substations because of safety concerns has been developed as a short-term work around.

[116] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 225-226 – Capital Detail by WBS Element for Substation Equipment Replacement Program (SERP).

Circuit breakers identified within this program are 115 kV, 66 kV, 16 kV, 12 kV, and 4 kV in voltage and are typically replaced with higher short-circuit duty rated circuit breakers. An alternative option to replacing overstressed circuit breakers is to electrically split the substation bus. This can reduce short circuit duty with the overstressed circuit breakers at the bus being split. However, this solution can only be accomplished at subtransmission substations and is not available for distribution substations. Splitting the bus at a distribution substation can potentially reduce the amount of available fault current needed to operate circuit breakers as required. In addition, the option of splitting a subtransmission substation bus is usually not a cost-effective solution compared to replacing circuit breakers because the downstream load of the split bus substation may require upgrading the existing transformer or installing a new parallel transformer to carry the load.

(2) <u>Basis for Capital Expenditure Forecast</u>

SCE's forecast expenditures for years 2023 to 2028, as shown in , are based on the maximum short-circuit duty on each of the overstressed circuit breakers on the distribution and subtransmission systems and the corresponding number of circuit breakers to be replaced by the overstress condition. The forecast varies based on need dates, execution timing, and the voltage class of the circuit breakers being replaced.

The forecast is developed from circuit breaker unit costs as a starting point for planned circuit breaker replacements. Unit Cost averages are calculated for each voltage class of circuit breakers for the period 2018 - 2022.[117] These are same unit costs used by the Substation Infrastructure Replacement program in SCE-02 Volume 1, Section IV.B.1. The annual expenditures for each circuit breaker are then split across the in-service year and the year prior.

As projects get closer to execution, additional details will factor into project specific adjustments for materials and construction execution. The final forecast for the years 2023 to 2028 is a mix of known adjustments for specific projects and unit costs for planned projects with operating dates in 2023 - 2028.[118] The total forecast for years 2023 to 2028 is $113.231 million.

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[117] Refer to WP SCE-02, Vol. 07, pp. 584-586 – Substation Equipment Replacement Program Forecast Methodology.

[118] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 227-229 – Substation Equipment Replacement Program Forecast Methodology.

e) Historic Sporting Events Cost Tracking Memorandum Account (HSECTMA)

(1) Program Description and Need

SCE's forecasts will be impacted by the 2028 Summer Olympics occurring in July 2028 and the 2026 World Cup taking place in June and July 2026.

Olympics events will take place at multiple venues and times within Los Angeles and the SCE service area. Specifics on event and facility locations and times have not been finalized. Venue and energy needs are being planned by a Los Angeles Department of Water & Power-led energy council to start in 2023-2024.

World Cup tournament matches will occur at SoFi Stadium (Inglewood) and other adjacent facilities. The anticipated order of magnitude is in the same range as the Super Bowl or a Los Angeles Rams NFL game, with SoFi anticipated to host several matches at various points of the tournament.

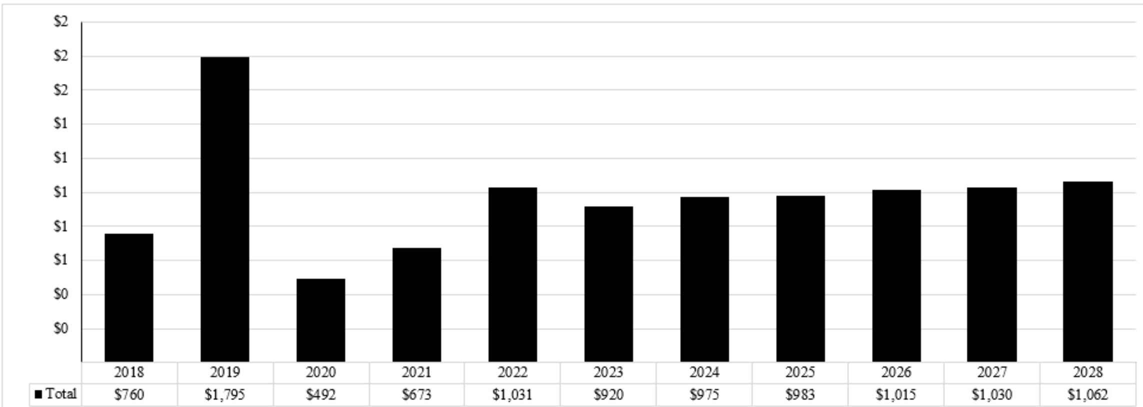
In establishing the HSECTMA, SCE will seek cost recovery after-the-fact for incremental spend for the 2028 Summer Olympics and the 2026 World Cup. This will align with policymakers' efforts to bring these events to the greater Los Angeles region. For the Olympics, O&M impacts are expected in 2027-2028 for inspections and repairs, business resiliency and security, work crews (including overtime) and equipment. Needed capital investments are still to be determined. Information specific to memorandum accounts can be found in SCE-07, Vol.01, Ch. V.

5. Land Rights Management

a) Program Description and Need for Program

Figure II-28 below provides the recorded and forecast capital expenditures for Land Rights Management.

Figure II-28
Land Rights Management Capital Expenditures Summary[119]
WBS Element CET-RP-OTVR-107900
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



SCE facilities may require passage along routes through property owned by another party. This category covers expenditures for various rights-of-way required for SCE facilities to pass through these locations.

b) <u>Basis for Capital Expenditure Forecast</u>

The Land Rights Management expenditures for the years 2023 to 2028 are estimated at approximately $5.984 million. The capital spending is required to cover costs associated with acquiring land rights not specifically provided for by a project budget. Examples include acquiring new access roads to allow for maintenance of existing facilities, acquisition of land rights over formerly government land that has been patented and sold to private parties, and acquisition of fee property to support operation and maintenance work.

Since the purpose of this request is to cover miscellaneous acquisitions that are not associated with a specific project or major project, whereby a land right must be acquired and the cost associated with the acquisition was not expected for the year, the forecast is generally based on historical costs with adjustments downward. The average cost for 2018 – 2022 was an average of about $950,000 per year, totaling $4.750 million. The years 2019 and 2022 were higher than normal, however,

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119 Refer to WP SCE-02, Vol. 07 Bk. B, pp. 230-231 – Capital Detail by WBS Element for Land Rights Management.

so a slight downward adjustment to the 2023 forecast was made to account for this. Example expenditures are permit-to-license conversion, load growth, and when no documented transmission rights are found. The forecast would cover all costs associated with acquiring the land right, document preparation, valuation, negotiations, and survey/mapping.

6. Climate Driven Distribution Circuit Ties for Reliability

a) Program Description and Need for Program

SCE's proposed climate-driven infrastructure projects include adaptations intended to address adverse impacts of climate change that we are witnessing today and into the future. SCE's recent Climate Adaptation and Vulnerability Assessment (CAVA) filing documented how projected changes in climate may impact utility assets, operations, and services. The full list of climate-informed projects proposed in the GRC is summarized in Exhibit SCE-01, Volume 2, Risk Informed Strategy & Business Plan, Chapter 6: Overview of Climate Adaptation and Vulnerability Assessment. The analysis considered climate-informed projections of flood and wildfire activity. Both flood and fire have potential to damage assets and cause a power outage or interruption for customers served by distribution circuits that traverse affected areas. The mitigation proposed here is to construct circuit ties to existing infrastructure adjacent to, and outside of, the impacted boundaries. The proposed projects are new to SCE's GRC testimony and are new programs intended to mitigate outage consequences for customers as a result of the harmful impacts driven by climate change.

The CAVA analysis documented potential trends in flooding and fire exposure as seen in climate projections. Climate projections indicate expected shifts in seasonal precipitation, as winter precipitation becomes more concentrated and fall and spring precipitation decrease. Although average precipitation is expected to remain relatively constant, precipitation patterns are expected to become more variable, with higher intensity events (i.e., peak precipitation days). Greater interannual variation resulting in whiplash between wet and dry periods may cause flood damage to be more severe.[120] Climate projections also show that fire exposure is projected to increase in and around High Fire Risk Areas (HFRAs), which already have an elevated risk of wildfires. Summer wildfires are projected to become more intense, particularly in mountainous regions.[121] Importantly, CAVA studied

[120] Climate Change Vulnerability Assessment Pursuant to D. 20-08-046. Section IV.C.1, pp. 80-82.

[121] Climate Change Vulnerability Assessment Pursuant to D.20-08-046, Section IV.D.1, pp. 104-108.

the risks wildfires pose to utility infrastructure and operations, and not the risks from ignitions associated with utility equipment.

SCE's CAVA identified areas that are at-risk of flooding and fire impacts and estimated the potential resulting outages for customers. Customers who rely on radial distribution circuits for electricity service are at-risk of experiencing climate-related outages if they are served by equipment that is either directly impacted by flooding or fire or is located downstream from directly impacted equipment. The CAVA recommended the construction of circuit ties to enable the transfer of unaffected equipment to neighbor circuits to maximize the number of customers remaining energized during a wildfire or flood event.[122] The adaptations proposed here are capital investments to construct those circuit tie lines, which would enable greater operational flexibility in flood- and fire-impacted areas and thereby reduce power outages or interruptions and increase reliability for customers. These tie lines are selected to recover the maximum number of customers possible from nearby circuits that can handle the additional load. In some cases, the tie line projects will require reconductoring of circuit lines to enable load transfers. A set of potential tie line locations have been identified; additional studies are ongoing to align climate-related needs with capacity upgrades and are expected to result in similar additional projects.[123]

b) <u>Compliance Requirement</u>

This program was designed in response to D.20-08-046, which requires investor-owned utilities to address identified climate vulnerabilities in the following GRC cycle.

c) <u>Basis for Capital Expenditure Forecast</u>

Table II-22 provides SCE's forecast capital expenditures (2025-2028) for the Climate-Driven Distribution (CDD) Circuit Ties Program.

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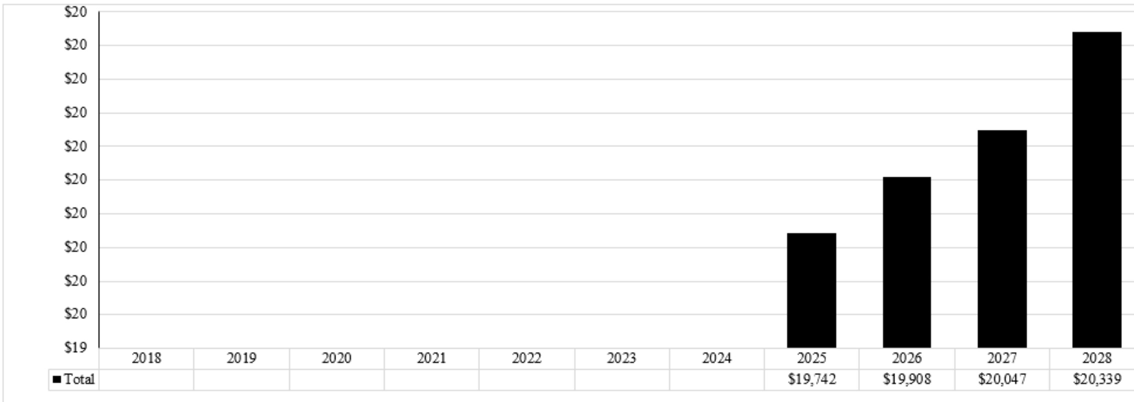
[122] Climate Change Vulnerability Assessment Pursuant to Decision 20-08-046, Section IV.C.2, p. 97 and Section IV.D.2, pp. 126-127.

[123] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 232-239 - Climate Driven Distribution Circuit Ties for Reliability.

Table II-22
Climate Driven Circuit Ties Capital Expenditures Summary[124]
WBS Element CET-PD-LGPCMTE
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



The forecast for this program was developed through several steps. As part of the CAVA, SCE simulated the potential damage to grid assets under wildfire and flooding scenarios based on climate projections and evaluated the potential for existing customers to be reenergized by existing adaptive capacity measures (i.e., existing circuit ties and transfers). Following the CAVA analysis, several additional analyses were performed to validate the proposed locations with additional wildfire and flooding exposure data, update tie path and length estimates and equipment needs, refine expected customer restoration outcomes,[125] and prioritize those circuit ties that maximize customer restoration. Proposed costs are estimated based on likely path locations between an affected circuit area and a new tie circuit and equipment that will be required to enable the new circuit tie connection.

Several alternatives to these circuit ties were proposed in the CAVA and evaluated. For wildfire-driven tie lines, alternatives included vegetation management, pole fire wrapping, and new circuit construction. Vegetation management is a viable short-term option to temporarily reduce wildfire risk; however, extensive vegetation management would be needed (e.g., completely clearing right-of-way) to prevent circuits from being damaged by fire. The long-term cost of a yearly program to execute that scope would be very high and difficult to incorporate into the existing

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[124] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 240-241 – Capital Detail by WBS Element for Climate Driven Circuit Ties.

[125] Refer to WP SCE-02, Vol. 07 Bk. B, pp. 232-239 – Climate Driven Distribution Circuit Ties for Reliability.

vegetation management workload. Fire wrapping poles is a viable option to reduce burn damage and decrease post-fire emergency repair efforts. However, fire wrapping decisions for distribution circuits were found to be more appropriate to leave to WMP efforts. New circuit construction was determined to be too expensive. For flooding-driven tie lines, an alternative is to replace pad mounted equipment with submersible equivalents. This option is being pursued for mainline air-insulated pad mounted switches as discussed in Exhibit SCE-02, Volume 1, Section II.C.5, and switches proposed for replacement are complementary to the circuit ties proposed in this program.

An additional alternative considered for both wildfire- and flooding-driven projects was to do no mitigation and allow for SCE emergency response and repair crews to fix and re-energize customers. This would mean that downstream customers not impacted by wildfire or flooding events would likely be out of power for multiple days. SCE is proposing circuit ties to prevent and reduce unnecessary customer outages to improve reliability for customers and reduce burden on emergency response crews.

III.

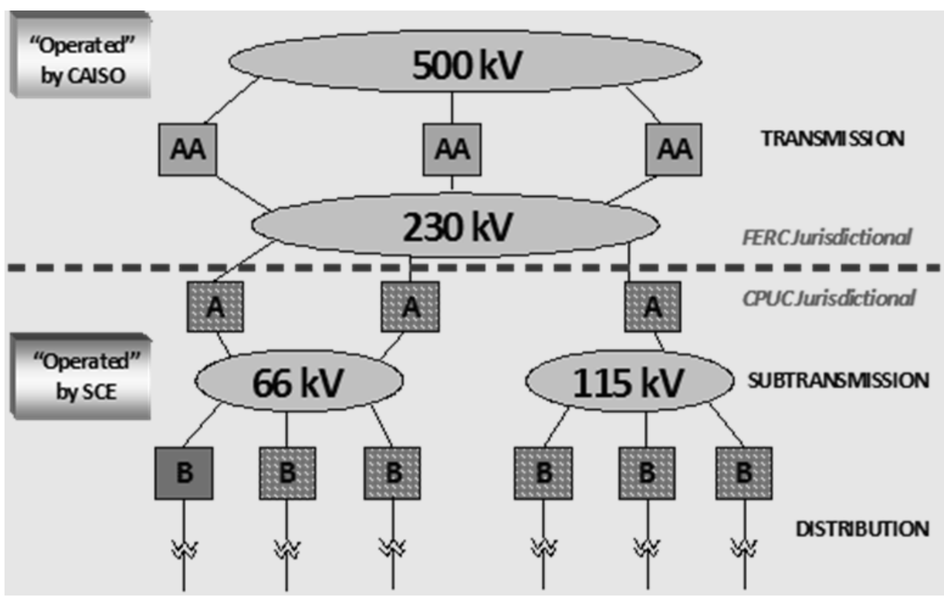
TRANSMISSION PROJECTS

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, while withstanding disturbances from system outages, storms, and other events.

SCE's remaining electric system, with the exception of portions of two subtransmission systems,[126] are under the operational control of SCE and within CPUC jurisdiction. Figure III-29 below illustrates the general jurisdictional split between the CPUC and FERC.

Figure III-29
General Jurisdictional Split Between CPUC and FERC

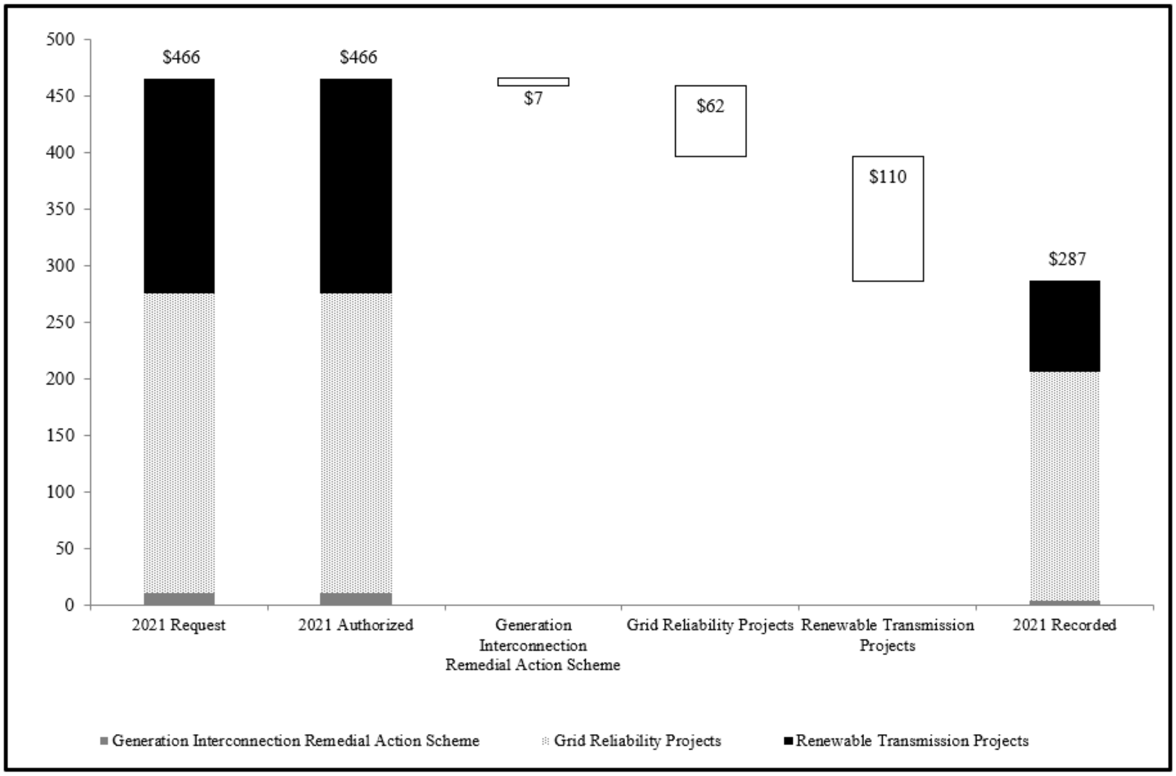


[126] The two subtransmission systems that have portions under the operational control of the CAISO (as they operate in parallel with the CAISO controlled transmission system) are: (1) the Antelope-Neenach-Bailey 66 kV lines, and (2) parts of the Victor-Kramer 115 kV System.

B. 2021 Decision

1. Comparison of Authorized 2021 to Recorded

Figure III-30
Authorized 2021 to Recorded Capital Expenditures[127]
(Total Company – Nominal $ Millions)



The 2021 GRC Decision requires that SCE compare the 2021 authorized amounts to the recorded amounts. As shown in Figure III-30, for Transmission Projects, SCE spent $177.7 million less than authorized in 2021. The drivers for this variance are specific to the projects and activities within Transmission Projects.

For Grid Reliability Projects, SCE spent $62 million less than authorized in 2021 (mostly FERC-jurisdictional). This was largely attributable to schedule delays for the Riverside Transmission Reliability Project that caused planned spend on property acquisition and materials to shift from 2021 to 2022. This underspending was partially offset by SCE spending more than authorized in 2021 for both the Mesa Project, due to changes in project scope, and the Eldorado-Lugo-Mohave Upgrade Project, due

[127] *See* WP SCE-07, Vol. 01, Authorized vs. Recorded.

to scope deferral of project activities from 2020 to 2021 and an increase in material costs due to supply chain constraints from the global COVID-19 pandemic.

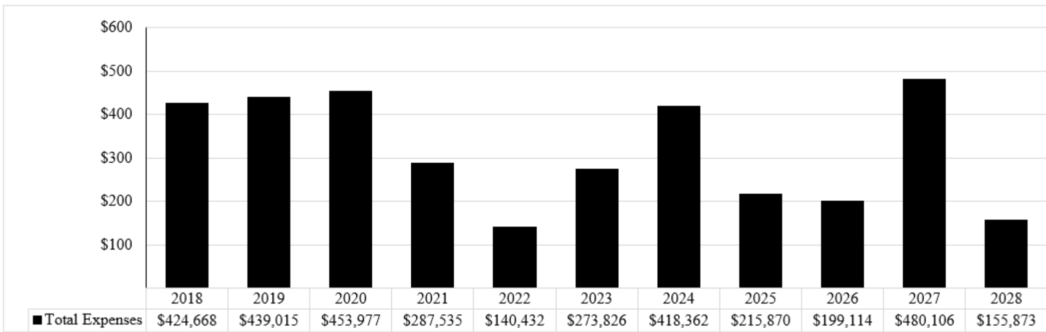
For Renewable Transmission Projects, SCE recorded $110 million less than authorized in 2021 (mostly FERC-jurisdictional). This was largely attributable to the completion of project construction for the West of Devers Upgrade Project in May 2021, which was expedited due to outage availability.

For Generation Interconnection Remedial Action Scheme, SCE spent $7 million less than authorized in 2021 (all FERC-jurisdictional). A major driver for adding a new Centralized Remedial Action Scheme (CRAS) is often additional interconnection of new generation, which is a customer-driven need. SCE's forecast did not specify projects due to uncertainty over which customers would enter into agreements and, accordingly, which CRAS would be needed. Ultimately, three new CRAS projects began work in 2021, but all had reduced expenditures due to project-specific delays that deferred expenditures to future years. Specifically, there were license issues for the Lugo-Victorville CRAS project, construction sequencing delays for the North of Lugo CRAS project, and labor resource issues which contributed to delays on the West of Colorado River Inland/Devers Extension CRAS project.

C. Transmission Projects

The recorded (2018-2022) and forecast (2023-2028) capital expenditures for Transmission Projects are shown below in Figure III-31.

Figure III-31
Transmission Projects Captial Expenditure Summary
Various WBS Elements[128]
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



While the majority of work for Transmission Projects falls within FERC jurisdiction, some of these projects include components under CPUC jurisdiction, including upgrades to the underlying subtransmission system and equipment supporting telecommunications, automation, and controls.[129] Both the total project and CPUC-jurisdictional expenditures forecast for these projects from 2023 to 2028 are shown in Table III-23 and Table III-24, respectively.

Table III-23
Transmission Projects Capital Expenditure Summary[130]
Various WBS Elements
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)

Line No	Program/Project Category	Prior	2023	2024	2025	2026	2027	2028
1	Grid Reliability Projects	$999,210	$192,110	$311,691	$136,659	$134,112	$293,801	$56,203
2	Renewable Transmission Projects	$765,352	$71,815	$87,841	$53,355	$51,278	$169,026	$89,526
3	Generation Interconnection RAS	$8,673	$9,901	$14,730	$18,179	$2,995	$2,972	$2,990
4	Transmission Economic Projects	$0	$0	$4,100	$7,677	$10,730	$14,307	$7,154
	Total	$1,773,234	$273,826	$418,362	$215,870	$199,114	$480,106	$155,873

[128] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 1-2 Transmission Projects Capital Expenditure Summary.

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

[130] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 1-2 Transmission Projects Capital Expenditure Summary.

Table III-24
Transmission Projects Capital Expenditure Summary
Various WBS Elements
Recorded 2018-2022/Forecast 2023-2028
(CPUC Jurisdictional – Nominal $000)

Line No	Program/Project Category	Prior	2023	2024	2025	2026	2027	2028
1	Grid Reliability Projects	$286,448	$12,797	$39,804	$35,891	$45,693	$33,824	$33,795
2	Renewable Transmission Projects	$37,271	$10,389	$6,513	$15,389	$11,288	$15,359	$13,087
3	Generation Interconnection RAS	-	-	-	-	-	-	-
4	Transmission Economic Projects	-	-	$4,100	$7,677	$10,730	$14,307	$7,154
	Total	$323,719	$23,185	$50,416	$58,956	$67,711	$63,490	$54,036

In general, a forecast and its associated expenditure plan are developed based on the scope of work, the timing of execution and activities, the costs of goods and services, and the applicable allocations, adjustments and/or allowances. Hence, the forecast reflects the cash requirement and reserve for the planned activities in an accounting period. Allocations are indirect costs, including overheads, attributable to execution. Adjustments and allowances are any informed changes to the forecast incorporating identified risks and opportunities, lessons learned, spending or resource constraints, studies of historic expenditures, and/or expert judgment.[131]

Transmission Projects are categorized as Grid Reliability, Renewable Transmission, Generation Interconnection Remedial Action Scheme (RAS), or Transmission Economic Projects. Details for Grid Reliability, Renewable Transmission Projects, and Transmission Economic Projects are provided in Sections III.C.1, III.C.2, and III.C.3 below. The Generation Interconnection RAS is not discussed further as there are no CPUC-jurisdictional capital expenditures forecast from 2023-2028.[132]

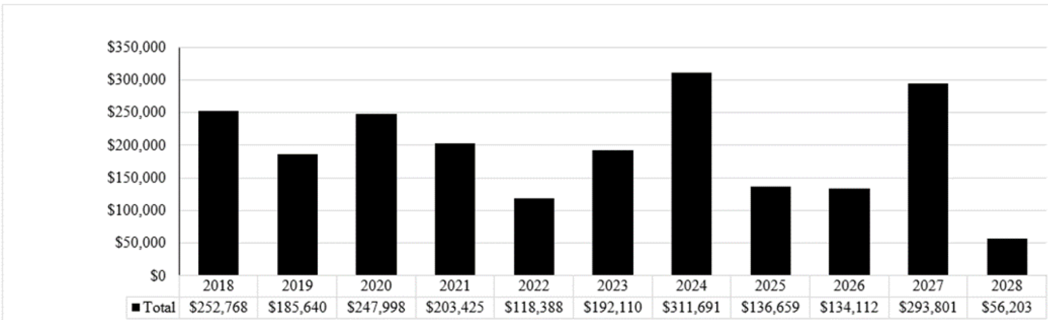
1. <u>Grid Reliability Projects</u>

The recorded (2018-2022) and forecast (2023-2028) capital expenditures for Grid Reliability Projects are shown below in Figure III-32.

[131] The forecast includes projected telecommunication infrastructure expenditures supporting planned projects related to Grid Reliability and Renewable Transmission Projects where no specific telecommunication scope estimates have been finalized at the time of filing.

[132] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 3-16 Capital Detail by WBS Element for Generation Interconnection Remedial Action Scheme.

Figure III-32
Grid Reliability Projects Capital Expenditure Summary
CWBS Element CET-ET-TP-RL[133]
(Total Company – Nominal $000)



The two tables below, Table III-25 (Total Company) and Table III-26 (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 2028.[134] Details regarding forecast expenditures for Grid Reliability Projects with CPUC-jurisdictional costs of less than $3 million each are provided in workpapers.[135]

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

Line No	Project No	Project Name	Operating Date	Prior	2023	2024	2025	2026	2027	2028
1	6957	WAMPAC	12/1/2028	-	-	$700	$8,000	$9,800	$14,775	$13,850
2	7884	Cerritos Channel Transmission Line Relocation Project	6/30/2026	$66,102	$301	$33,929	$31,402	$20,193	-	-
3	8519	Barre 230 kV Switchrack to Breaker-and-a-Half	6/1/2026	-	-	$9,000	$18,000	$11,250	$6,750	-
			Subtotal	**$66,102**	**$301**	**$43,629**	**$57,402**	**$41,243**	**$21,525**	**$13,850**
		Projects with CPUC Jurisdictional cost < $3 M		$36,336	$133,251	$221,262	$68,089	$75,194	$253,228	$22,408
		Projects with operating date outside of GRC window		$896,771	$58,557	$46,799	$11,168	$17,675	$19,049	$19,945
			Total	**$999,210**	**$192,110**	**$311,691**	**$136,659**	**$134,112**	**$293,801**	**$56,203**

[133] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 17-65 Capital Detail by WBS Element for Grid Reliability Projects.

[134] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 66-70 Grid Reliability Projects Over $3M CPUC-jurisdictional Costs.

[135] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 71-72 Grid Reliability Projects Less than $3M CPUC-jurisdictional Costs.

Table III-26
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	2023	2024	2025	2026	2027	2028
1	6957	WAMPAC	12/1/2028	-	-	$700	$8,000	$9,800	$14,775	$13,850
2	7884	Cerritos Channel Transmission Line Relocation Project	6/30/2026	$52,352	$151	$16,965	$15,701	$16,962	-	-
3	8519	Barre 230 kV Switchrack to Breaker-and-a-Half	6/1/2026	-	-	-	-	-	-	-
			Subtotal	**$52,352**	**$151**	**$17,665**	**$23,701**	**$26,762**	**$14,775**	**$13,850**
		Projects with CPUC Jurisdictional cost < $3 M		$170	$41	$1,021	$1,021	$1,256	-	-
		Projects with operating date outside of GRC window		$233,926	$12,605	$21,118	$11,168	$17,675	$19,049	$19,945
			Total	**$286,448**	**$12,797**	**$39,804**	**$35,891**	**$45,693**	**$33,824**	**$33,795**

a) Project Description and Need for Activity

Grid Reliability Projects are planned on the portion of SCE's system under CAISO operational control.[136] They are developed as part of CAISO's Transmission Planning Process (TPP)[137] and are required to support system reliability and compliance with North American Electric Reliability Corporation (NERC),[138] Western Electric Coordinating Council (WECC),[139] and CAISO[140] system performance standards and criteria. In addition, SCE has its own transmission planning criteria comprised of internal technical design and planning practices. The costs and scope of Grid Reliability Projects are largely under FERC jurisdiction but may contain certain CPUC-jurisdictional components in scope.

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

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136 California Independent System Operator Corporations, Fifth Replacement FERC Electric Tariff, Section 24 (Sep. 1, 2022), *available at* http://www.caiso.com/Pages/DocumentsByGroup.aspx?Group=Conformed-Tariff-as-of-Sep1-2022.pdf%20as%20of%20October%2019 (as of October 19, 2022).

137 *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.

138 North American Electric Reliability Corporation, Transmission System Planning Performance Requirements, TPL-001-5 *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf (as of October 19, 2022).

139 Western Electric Coordinating Council, WECC Criterion TPL-001-WECC-CRT-3.2, *available at* https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf (as of March 9, 2023).

140 California ISO Planning Standards effective February 2, 2023 *available at* http://www.caiso.com/Documents/ISO-Planning-Standards-Effective-Feb22023.pdf (as of March 9, 2023).

- Evaluate the performance of the SCE transmission system under peak and off-peak conditions for near-term and long-term planning horizons;[141]
- Determine transmission constraints under stressed system conditions;[142]
- Identify upgrades needed to maintain the reliability of the transmission system and comply with NERC Reliability Standards, WECC Criteria, CAISO Planning Standards, and SCE's transmission Planning criteria.

SCE's ATRA is performed in parallel with the CAISO TPP under the CAISO's FERC jurisdictional tariff.[143] SCE's Grid Reliability Projects are identified in the CAISO TPP and subject to review and approval by the CAISO Board of Directors and cost recovery based upon the CAISO Transmission Access Charge (TAC).

The Grid Reliability Projects recorded capital expenditures vary from year-to-year, as shown above in Figure III-32. The primary driver is the timing associated with the major transmission projects in-flight. For example, the 2022 expenditures were lower than in previous years due to the following: (1) the completion of Moorpark-Pardee No. 4 220 kV new transmission line project and Mesa project in the first half of 2022, (2) project delays for the Eldorado - Lugo - Mojave Line Upgrade project,[144] and (3) the Riverside Transmission Reliability Project being placed on hold in June 2022.[145]

In addition to this TPP work, during this GRC period, SCE will deploy Wide Area Monitoring, Protection and Control (WAMPAC) capabilities. This is a new activity in this GRC. SCE has been deploying phasor measurement units (PMUs) across its bulk power system to meet NERC PRC-002, and these PMU measurements have provided SCE with vast quantities of data detailing the

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[141] For planning horizons, "near-term" refers to one- to five-years-out while "long-term" refers to six- to ten-years-out.

[142] "Stressed system conditions" refers to instances involving the electric grid when there is maximum transmission line loading.

[143] California Independent System Operator Corporations, Fifth Replacement FERC Electric Tariff, Section 24 (Sep. 1, 2022), *available at* http://www.caiso.com/Documents/Conformed-Tariff-as-of-Sep1-2022.pdf (caiso.com) (as of October 19, 2022).

[144] Factors in the Eldorado Lugo Mohave project delay include material shortages and outage restrictions.

[145] This project was placed on hold due to a decision by the Riverside City Council to explore an alternative project design.

condition of the grid. However, robust tools are needed to transform this accurate high-rate measurement data into actionable information, so future PMUs can contribute even more to the efficient, safe, and reliable planning and operation of SCE's electric system. SCE has also deployed an initial visualization software that displays basic phasor measurement information to system operators and engineers, known as Wide-Area Situational Awareness System (WASAS). The advancement of sensor, communication, and information technologies will enable the deployment of the more robust and comprehensive WAMPAC to leverage existing PMUs and maximize the value of synchronized measurements.

In this GRC period, WAMPAC will primarily focus on building up key monitoring capabilities, including Model Validation, System Disturbance Monitoring, Oscillation Stability Monitoring, Power Quality Monitoring, Inertia Monitoring, Short Circuit Capacity Analysis, Power Angle Stability Analysis, Linear State Measurement, and Preventive Stability Assessment. Dedicated software (e.g., synchro-phasor analytics) and platforms integrated with SCE's Energy Management System (EMS) will process the data and provide operators and engineers with real-time situational awareness, event prediction, and event analysis. Presently, the locations and types of disturbances that occur are found by after-event analysis. WAMPAC, however, will quickly alert system operators about emerging threats to transmission system stability (e.g., phase angle separations[146]) during the event, enabling faster preventative action to avoid wide-scale blackouts. The current proposal for WAMPAC is largely dependent on PMUs as the primary device to collect data. Though there are other technologies that may be able to monitor a subset of power quality metrics, a PMU-based strategy is optimal for SCE as it builds on and integrates best with existing grid infrastructure from previous investments.

With the dominance of inverter-based resources (IBRs) (e.g., intermittent solar, wind, and battery energy storage) and the projected retirement of natural gas plants that provide significant amounts of steady, controllable energy, grid operators will need to evolve their operations to maintain grid stability. The voltage, current, and frequency monitoring capabilities deployed through WAMPAC are crucial to sustaining grid stability through the transition to renewables. Due to the changes in the electric grid, this sensing will be used to identify issues that are not visible to the traditional monitoring techniques of the past because enhanced system visibility and understanding and

[146] Phase angle separation refers to the angular separation between two distant buses in the system. Large phase angle separations are indicative of high system stress conditions and hinder the ability to reclose the transmission circuit.

faster response time are required for dealing with the performance of a grid supplied predominantly by IBRs.

Over the past six years, SCE has observed an increase in IBR performance issues, as manifested by widespread IBR loss events that have been analyzed and documented by NERC with support and PMU data from SCE. More than six NERC events[147] have occurred in SCE territory since 2016, leading to hundreds of MWs of generation tripping off. While SCE presently has the capability to monitor the electrical system and perform off-line event analysis, we do not have automated analytical capabilities such as real-time oscillation detection tools and real-time monitoring of phase angle difference as a measurement of grid security both pre- and post-contingency. System oscillations, including low frequency oscillations, forced oscillations, inter-area oscillatory modes, and phase angle differences (i.e., phase angle difference between transmission line terminals and phase angle difference across the wider electrical system, which may escalate and become large-scale contingencies) may go unnoticed until it is too late. The capabilities deployed through WAMPAC will help mitigate these issues by identifying precursor signs of these events and/or these events in the early stage of occurring and notifying the system operator in time to prevent the larger scale event from happening. For example, WAMPAC will identify when oscillations are occurring and determine if the oscillations are limited locally within their footprint or are more widespread.

In addition, our current engineering use for synchrophasor data is limited to event analysis. With WAMPAC, however, SCE's ability to perform post-event analyses and validate power plant and system models will be enhanced by the post-event analysis and model validations functionalities being provided by the system. Building these monitoring capabilities through WAMPAC is an essential first step in identifying effective mitigations to these events. With the new WAMPAC capabilities, SCE will improve its responses to the rising number of system disturbances and more effectively determine the next set of measures needed to minimize the occurrence and impact of future events. These measures may range from helping the IBR facilities tune their generation controls to identifying operator actions (e.g., reducing power transfer across transmission paths, making topological changes, etc.) to reduce the risk of the event.

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[147] North American Electric Reliability Corporation, Major Event Analysis Report: October 2017 Canyon 2 Fire Disturbance Report; April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report; July 2020 San Fernando Solar PV Reduction Disturbance Report; and June-August 2021 CAISO Solar PV Disturbance Report, *available at* https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx (accessed April 3, 2023).

SCE forecasts $47 million in capital expenditures from 2023-2027 for WAMPAC.[148,149] This cost primarily consists of the installation of 10 additional PMUs and the synchro-phasor analytics software to process phasor data and perform event analysis. These additional PMUs are needed to fill in existing gaps in coverage on 220 kV transmission buses and will build on previous deployments of PMUs, which were installed to meet NERC PRC-002. NERC PRC-002, while setting the standard for NERC event analysis, does not guarantee observability of every electrical bus. Many IBRs are being connected to those non-observable bus, thus requiring the additional PMUs. The synchro-phasor analytics software is needed to process phasor data and perform event analysis. This forecast also includes the costs for software implementation support, hardware for the expansion of Grid Data Center (GDC)and Grid Services Integration Lab (GSIL) environments to support the application, and the labor required to deploy the software and hardware. These costs support the integration, implementation, and testing of the system prior to deployment to the production environment. Also included in the 2024-2028 forecast are employee led efficiency savings for an average of $0.243 million per year related to optimizing the mix of supplemental versus SCE personnel.[150,151]

2. Renewable Transmission Projects

The recorded (2018-2022) and forecast (2023-2028) capital expenditures for Grid Reliability Projects are shown below in Figure III-33.

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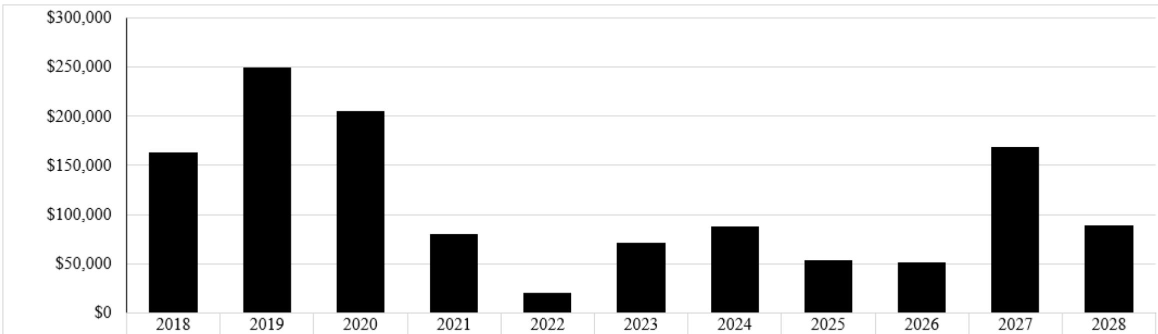
[148] SCE has also identified some one-time O&M expenditures needed to support this effort; however, these O&M expenses have not been included in SCE's GRC request. The WAMPAC O&M expenditures considered as ongoing are further discussed in SCE-06, Vol. 01, Enterprise Technology.

[149] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 73-76 Wide Area Monitoring Protection and Control Forecast.

[150] Also included is $0.0036 million of savings in 2023. Please refer to SCE-06, Vol. 03 for additional details.

[151] The forecast incorporates an adjustment to reflect changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

Figure III-33
Renewable Transmission Projects Capital Expenditure Summary
CWBS Element CET-ET-TP-RN[152,153]
(Total Company – Nominal $000)



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
■ Total	$163,137	$249,533	$205,129	$79,691	$20,066	$71,815	$87,841	$53,355	$51,278	$169,026	$89,526

There are no Renewable Transmission Projects in SCE's GRC forecast that have over $3 million in CPUC- jurisdictional capital expenditures and are expected to be completed and operational by the end of 2028.[154] Therefore, the two tables below, Table III-27(Total Company) and Table III-28 (CPUC-jurisdictional only), provide the totals for (1) the Renewable Transmission Projects that have less than $3 million in CPUC- jurisdictional capital expenditures and are expected to be completed and operational by the end of 2028, and (2) the Renewable Transmission Projects that have operating dates outside of the GRC window. Details regarding forecast expenditures of Renewable Transmission Projects with CPUC-jurisdictional costs of less than $3 million each are provided in workpapers.[155]

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152 Refer to WP SCE-02, Vol. 07 Bk. C, pp. 77-175 Capital Detail by WBS Element for Renewable Transmission Projects.

153 The forecast incorporates an adjustment to reflect changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

154 As discussed below, the Renewable Transmission Projects GRC forecast was finalized for SCE's GRC filing by March 2023. Subsequently, in April 2023, CAISO issued a new draft TPP plan that, if adopted, would require SCE to spend significantly more on Renewable Transmission Projects during this GRC cycle than previously anticipated. Because of this potential for significant costs increases during this GRC cycle that are both outside of SCE's control and unable to be reflected in SCE's forecast for timing reasons, SCE is requesting authorization to open a memorandum account to track the CPUC-jurisdictional capital-related revenue requirement and capital-related expense associated with costs spent on Renewable Transmission Projects that are incremental to the amounts authorized in the 2025 GRC based on SCE's March 2023 forecast. For more information on this request, please see SCE-07, Volume 1, Section V.B.2.

155 Refer to WP SCE-02, Vol. 07 Bk. C, pp. 176-177 Renewable Transmission Projects Less than $3M CPUC-jurisdictional Costs.

Table III-27
Renewable Transmission Projects Capital Expenditure Summary
CWBS Elements CET-ET-TP-RN
(Total Company – Nominal $000)

Line No	Project No	Project Name	Operating Date	Prior	2023	2024	2025	2026	2027	2028
1				-	-	-	-	-	-	-
			Subtotal	-	-	-	-	-	-	-
		Projects with CPUC Jurisdictional cost < $3 M		$4,873	$10,498	$61,542	$53,355	$51,278	$169,026	$89,526
		Projects with operating date outside of GRC window		$760,479	$61,317	$26,300	$0	$0	$0	$0
			Total	**$765,352**	**$71,815**	**$87,841**	**$53,355**	**$51,278**	**$169,026**	**$89,526**

Table III-28
Renewable Transmission Projects Capital Expenditure Summary
CWBS Elements CET-ET-TP-RN
(CPUC Jurisdictional – Nominal $000)

Line No	Project No	Project Name	Operating Date	Prior	2023	2024	2025	2026	2027	2028
		Projects with CPUC Jurisdictional cost								
			Subtotal	-	-	-	-	-	-	-
		Projects with CPUC Jurisdictional cost < $3 M		$51	$585	$2,474	$15,389	$11,288	$15,359	$13,087
		Projects with operating date outside of GRC window		$37,220	$9,803	$4,039	-	-	-	-
			Total	**$37,271**	**$10,389**	**$6,513**	**$15,389**	**$11,288**	**$15,359**	**$13,087**

a) <u>Project Description and Need for Activity</u>

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.[156] SCE performs interconnection studies with CAISO under CAISO's FERC-jurisdictional tariff[157] and NERC Reliability Standards, and identifies interconnection projects specific to each generator enabling them to interconnect without adverse effects on system reliability.

[156] 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* https://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx (as of October 27, 2022).

[157] California Independent System Operator Corporations, Fifth Replacement FERC Electric Tariff, Section 24 (Sep. 1, 2022), *available at* http://www.caiso.com/Documents/Conformed-Tariff-as-of-Sep1-2022.pdf (as of October 27, 2022). *See* also, CAISO Generator Interconnection Procedures, Appendix Y, *available at* https://www.caiso.com/Documents/AppendixY-GeneratorInterconnectionProcedures-for-InterconnectionRequests-asof-Sep1-2022.pdf (as of October 27, 2022).

Policy-driven projects are identified by CAISO through the TPP[158] as those enabling the grid to support State and Federal directives. This includes California's renewable portfolio standard (RPS) to source 33 percent of energy sales from renewable resources by 2020 and Senate Bills 350[159] and 100[160] mandating renewable energy and greenhouse gas (GHG) reduction targets, respectively, over designated periods. Achieving these objectives requires the development and interconnection of renewable generating resources and the construction of new infrastructure to deliver their output to customers.

The Renewable Transmission Projects historical capital expenditures vary from year-to-year, as shown above in Figure III-33. The primary driver is the timing associated with the major transmission projects in flight. For example, most of the 2018-2022 capital expenditures are associated with the West of Devers project. Because the West of Devers 230 kV Upgrades went into service in May 2021, 2021 and 2022 expenditures were lower than in previous years.

The Renewable Transmission Projects forecasts shown in Tables III-31 and III-32 were finalized for SCE's GRC filing by March 2023. Subsequently, in April 2023, CAISO issued a new draft TPP plan[161] that, if adopted, would require SCE to spend significantly more on Renewable Transmission Projects during this GRC cycle than previously anticipated. Specifically, this plan would require SCE to sponsor multiple large Renewable Transmission Projects not previously contemplated, with total spend on these required projects during this GRC cycle estimated at around $2 billion (total company). In addition to these required projects, this draft plan also includes three competitive projects within or adjacent to SCE service territory. At this time, SCE expects a final transmission plan to be adopted by CAISO in May 2023. Because of this potential for significant costs increases during this

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[158] 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 (as of October 27, 2022). http://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf (as of October 27, 2022).

[159] S.B. 350, Ch. 547 (Calif. 2015), *available at* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350 (as of October 27, 2022).

[160] S.B. 100, 2021-2022 Reg. Sess. (Calif. 2020), *available at* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB100 (as of October 27, 2022).

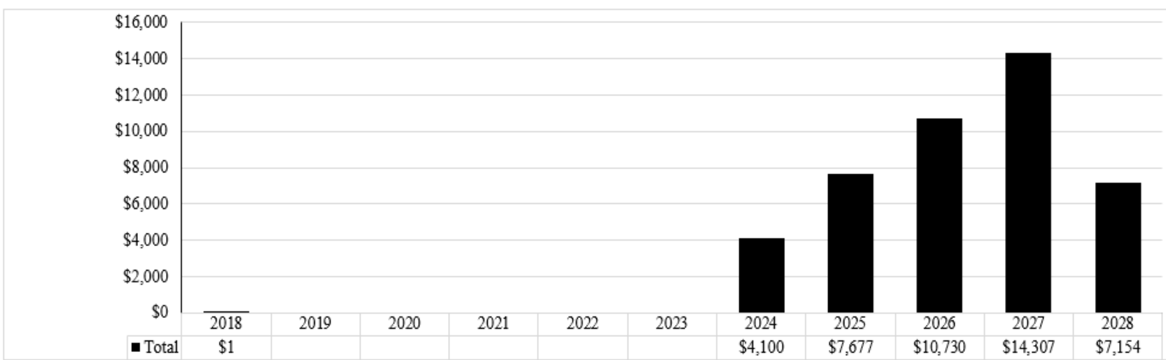
[161] CAISO, 2022-2023 Transmission Plan (April 3, 2023), *available at* http://www.caiso.com/InitiativeDocuments/Draft-2022-2023-Transmission-Plan.pdf.

GRC cycle that are both outside of SCE's control and unable to be reflected in SCE's forecast for timing reasons, SCE is requesting authorization to open a memorandum account—the Renewable Transmission Projects Memorandum Account (RTPMA)—to track the CPUC-jurisdictional capital-related revenue requirement and capital-related expense associated with costs spent on Renewable Transmission Projects that are incremental to the amounts authorized in the 2025 GRC based on SCE's March 2023 forecast. For more information on this request, please see SCE-07, Volume 1, Section V.B.2.

3. <u>Transmission Economic Projects</u>

The recorded (2018-2022) and forecast (2023-2028) capital expenditures for Grid Reliability Projects are shown below in Figure III-34.

Figure III-34
Transmission Economic Projects Capital Expenditure Summary
CWBS Element CET-ET-TPEC[162]
Recorded 2018-2022/Forecast 2023-2028
(Total Company – Nominal $000)



The two tables below, Table III-29 (Total Company) and Table III-30 (CPUC-jurisdictional only), list the Transmission Economic Projects that have over $3 million in CPUC-jurisdictional capital expenditures and are expected to be completed and operational by the end of 2028. Details regarding forecast expenditures of Transmission Economic Projects are provided below.

162 Refer to WP SCE-02, Vol. 07 Bk. C, pp. 178-179 Capital Detail by WBS Element for Transmission Economic Projects.

Table III-29
Transmission Economic Projects Capital Expenditure Summary
CWBS Elements CET-ET-TPEC
(Total Company – Nominal $000)

Line No	Program Name	2023	2024	2025	2026	2027	2028
1	Ambient-Adjusted Ratings	-	$4,100	$4,100	-	-	-
2	Dynamic Line Ratings	-	-	$3,577	$10,730	$14,307	$7,154
	Total		**$4,100**	**$7,677**	**$10,730**	**$14,307**	**$7,154**

Table III-30
Transmission Economic Projects Capital Expenditure Summary[163]
CWBS Elements CET-ET-TPEC
(CPUC Jurisdictional – Nominal $000)

Line No	Program Name	2023	2024	2025	2026	2027	2028
1	Ambient-Adjusted Ratings	-	$4,100	$4,100	-	-	-
2	Dynamic Line Ratings	-	-	$3,577	$10,730	$14,307	$7,154
	Total		**$4,100**	**$7,677**	**$10,730**	**$14,307**	**$7,154**

a) <u>Project Description and Need for Activity</u>

Transmission Economic Projects refers to projects identified to reduce transmission ratepayer costs through a variety of drivers, such as mitigating transmission congestion or reducing costs associated with the requirement to contract a minimum amount of generation in an area for reliability purposes according to the Local Capacity Requirement (LCR).[164] In this GRC period, SCE must complete two Transmission Economic Projects to (1) improve the accuracy of line ratings related to Ambient-Adjusted Ratings (AARs) in order to comply with the recently-issued FERC Order 881, and (2) to enable Dynamic Line Ratings (DLRs).

On December 16, 2021, FERC issued Order 881 directing transmission providers to implement a transparent and accurate process for updating transmission line ratings electronically due

[163] After the GRC forecast was finalized, SCE identified that the Ambient-Adjusted Ratings and Dynamic Line Ratings forecasts were incorrectly classified as 100% CPUC-jurisdictional. In fact, most of these forecast costs are FERC jurisdictional. SCE will issue a post-filing errata to align the asset classification to the proper FERC and CPUC jurisdictional breakdown.

[164] California Independent System Operator Corporations, Fifth Replacement FERC Electric Tariff, Section 24 (Sep. 1, 2022), *available at* http://www.caiso.com/Documents/Conformed-Tariff-as-of-Sep1-2022.pdf (accessed April 11, 2023).

to a FERC finding that static ratings are not accurate and "inaccurate transmission line ratings result in Commission-jurisdictional rates that are unjust and unreasonable."[165] Inaccurate transmission line ratings impact customers because the line rating defines the capability to transfer power between portions of the transmission system, such as between generators and load. If the documented line rating is lower than the actual line capability, the market may result in higher wholesale rates. For example, the market may procure more expensive generation when lower cost power was available because the model incorrectly assumed the line was at capacity and could not deliver the lower cost power. As such, the order requires transmission providers to increase the accuracy of transmission line ratings by continually adjusting them based on ambient weather conditions, known as AARs, instead of assuming ratings based on a single air temperature throughout the season or year. The order will impose operational and planning requirements on SCE to determine transmission ratings based on current and forecasted weather conditions, calculate this information in accordance with FERC Order 881, and transmit the ratings to the CAISO. The projected go-live date for this FERC requirement is July 2025.

To meet the requirements of FERC Order 881 for the required July 2025 go-live date, SCE will need to collaborate closely with both FERC and the CAISO through all stages of development. This will include developing initial project concepts, identifying methodologies required for weather calculations, developing exception methodologies, and identifying coordination requirements for interconnection points between utilities. Once completed, additional development will be required to test and validate the methodologies constructed prior to incorporation into SCE's Energy Management System (EMS) and the CAISO's updated reporting mechanism.

After implementing AARs to comply with FERC Order 881, SCE will then enable Dynamic Line Ratings (DLRs) by utilizing sensors to incorporate additional real-time weather data such as wind speed into the line rating calculation. Although not required by FERC Order 881, the order acknowledges that DLRs can further increase transmission line rating accuracy,[166] and FERC has opened a proceeding to continue evaluating the economic and reliability benefits from DLRs such as: correcting for current and forecast weather inaccuracies due to terrain or lack of weather stations, offering additional ampacity through critical transmission paths; additional capture of data to incorporate

[165] 18 CFR Part 35, Docket No. RM20-16-000, Order No. 881(Dec. 16, 2021), Paragraph 3 (issued December 16, 2021), *available at* https://www.ferc.gov/media/e-1-rm20-16-000 (accessed April 2, 2023).

[166] 18 CFR Part 35, Docket No. RM20-16-000, Order No. 881(Dec. 16, 2021) *available at* https://www.ferc.gov/media/e-1-rm20-16-000. Refer to paragraph 7.

dynamic variables into ampacity calculation variables like wind speed, wind direction, and solar irradiation, adding ampacity headroom to be utilized in CAISO markets; and adding additional monitoring capabilities to ensure safe operation of increased ampacity in areas of high concern.[167] With the additional benefits offered by DLRs, SCE expects ampacity benefits of at least five percent in coastal and mountainous regions where broadly-available weather data lacks precision,[168] as well as safety benefits associated with more granular performance monitoring in transmission paths overlapping with HFRA regions.

Based on the expected development and IT upgrades needed, SCE forecasts capital expenditures of $43.9 million from 2024-2028 for complete integration of AARs/Dirs.'

This development and integration work is broken into two projects. The first project requires SCE to develop a system to calculate AARs on the CAISO-controlled bulk power system using publicly available weather data. SCE forecasts $4.1 million in each of 2024 and 2025 for this project for a total of $8.2 million, which will enable SCE to achieve compliance with FERC Order 881 by July 2025.[169] These costs primarily consist of the labor needed for development and software costs associated with necessary EMS system upgrades.

For the second project, SCE will account for weather station accuracy concerns by implementing sensors on existing structures to measure the environmental conditions more accurately on transmission lines and thus enable DLRs. Without DLR monitoring devices, SCE's preliminary estimates project that SCE will not have the confidence in the weather data to realize the full benefits of weather-adjusted ratings for approximately 20% of the bulk power system (primarily the mountainous, coastal, and HFRA regions). SCE forecasts $35.7 million for this project from 2025 through 2028.[170] These costs include the additional software and hardware costs associated with installing new sensor equipment in areas in which more granular weather data is required, as well as the labor required to install and connect this equipment.[171]

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[167] FERC Docket No. AD22-5-000 *available at* https://www.ferc.gov/media/ad22-5-000.

[168] U.S. Dept. of Energy, Oncor Electric Delivery Company, "Dynamic Line Rating" demonstration results is *available at* https://www.smartgrid.gov/project/oncor_electric_delivery_company_dynamic_line_rating.

[169] Refer to WP SCE-02 Vol. 07 Bk. C, pp. 180-182 Ambient Adjusted Rating Forecast.

[170] Refer to WP SCE-02 Vol. 07 Bk. C, pp. 183-186 Dynamic Line Rating Forecast.

[171] The forecast incorporates an adjustment to reflect certain changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

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 O&M within the Engineering BPE falls into two GRC activities, Grid Engineering and Load Side Support.

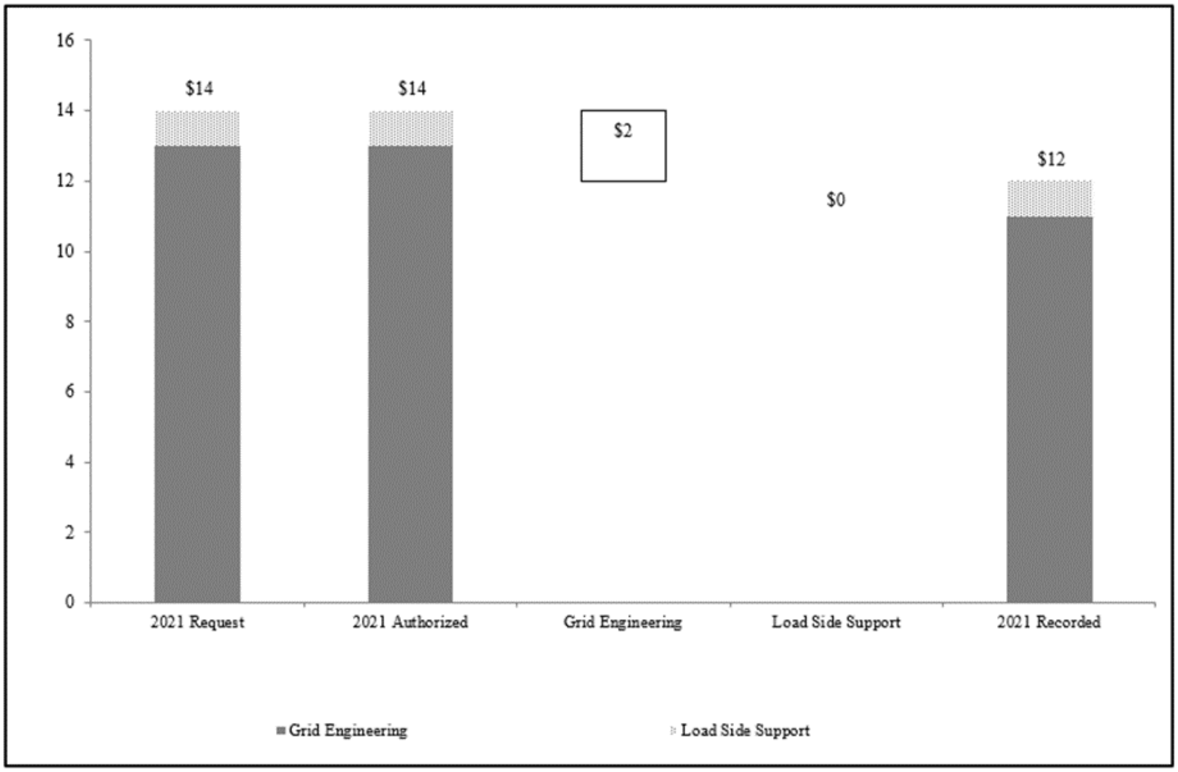
The Grid Engineering GRC activity includes identifying necessary system modifications and expansions on our transmission grid to: (a) help ensure compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) Reliability Standards & Criteria; and (b) participate in local, regional, and state activities that involve the planning of new generation, transmission lines, and substations. In addition, Grid Engineering includes the engineering activities to support the development of detailed engineering designs for system upgrades, modifications, and additions to support the construction, maintenance, and operations of SCE's electrical facilities across all voltages. 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 activity captures the investigation of the concern and the solution development.

B. 2021 Decision

1. Comparison of Authorized 2021 to Recorded

The 2021 GRC Decision requires SCE to compare the 2021 authorized amounts to the recorded amounts. Figure IV-35 below compares the authorized and recorded amounts for the Engineering BPE.

Figure IV-35
Comparision of Authorized 2021 to Recorded Engineering O&M Expenses[172]
(Constant 2022 $ Millions)



For Grid Engineering, SCE recorded $2.650 million less than authorized in 2021. This variance was due to projects being deferred and/or cancelled due to contractors experiencing work restrictions because of the COVID-19 pandemic and labor vacancies remaining unfilled.

For Load Side Support, SCE recorded $0.069 million less than authorized in 2021, which is within normal operating expectations.

C. O&M Forecast

1. Grid Engineering

a) Work Description and Need

SCE's engineers perform activities that support the desktop analysis/assessment, modification, and operation of the power system. From long-term planning activities to near-term design

[172] *See* SCE-07, Vol. 01, Authorized vs. Recorded.

and engineering activities (including field support), this work supports all voltages of SCE's transmission and distribution systems and the various stages of grid engineering.

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

SCE's transmission system performance and configuration are routinely evaluated against mandatory NERC Reliability Standards,[173] WECC Reliability Standards/Criteria,[174] and the CAISO Planning Criteria.[175] Necessary modifications and system expansions must be identified and planned to help ensure compliance with these standards and criteria. System modifications include adding new substations, expanding existing facilities, upgrading equipment, installing voltage support equipment, adding new transmission lines, adding capacity to existing lines, and reconfiguring the system.

As part of evaluating the future reliability of the SCE transmission system, SCE participates in root cause evaluations of major disturbances on the Western Interconnection[176] and in developing recommendations to prevent similar system disturbances.

SCE transmission planners participate in developing CAISO, WECC, and NERC Reliability Standards/Criteria. They also participate in local, regional, and state activities that involve the planning of new generation, transmission lines, and substations. The studies and planning processes managed by this group require an advanced understanding of bulk power flow, engineering standards, and quantitative modeling. This work is conducted by engineers who have expertise in SCE's

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[173] NERC Reliability Standards, *available at* https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx (as of October 27, 2022).

[174] Western Electric Coordinating Council, Reliability Standards/Criteria *available at* https://www.wecc.org/Standards/Pages/Default.aspx (as of October 27, 2022).

[175] CAISO Planning Criteria, *available at* https://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf (as of October 27, 2022).

[176] 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* https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0 (as of October 27, 2022).

transmission system and experience in electric system planning and regulatory policy. SCE also uses contract personnel to perform work associated with specialized projects. These activities are necessary to support transmission system reliability and safety.

In addition to work that supports planning activities, Grid Engineering includes the engineering activities to support the detailed design, project-specific studies, procurement of material and electrical equipment, construction, maintenance, and operations of SCE's electrical facilities across all voltages. This includes developing detailed engineering designs for system upgrades, modifications, and additions to the transmission system, subtransmission system, and distribution system. These activities include:

1. Performing critical and/or project-specific engineering studies/assessments (e.g., System Coordination Studies, Real-time Digital Simulation, Out-of-Step, Substation Capacity Analysis, etc.) necessary to support requests for interconnection or non-standard service requests. Engineering interconnection studies involve evaluating the impact of the interconnection on our equipment/facilities. The studies are necessary to determine if existing equipment/facilities are adequate or if SCE must add/upgrade equipment/facilities to accommodate the interconnection.

2. Assisting and guiding field personnel in properly installing, operating, and maintaining transmission, substation, and distribution equipment and assets.

3. Performing evaluations on poles/towers on our system so that structures are properly designed to withstand impacts from high wind-ice combinations and unbalanced longitudinal wire loads.

4. Providing equipment support, such as:

   a. Performing equipment verification and various engineering studies.

   b. Evaluating and/or testing equipment developed by vendors for potential widespread use on the SCE system.

   c. Performing analyses on equipment or devices that may provide safety and/or reliability benefits (e.g., using fuses versus reclosing device on the distribution network).

5. Assessing and designing protective relaying schemes, system controls, and automation schemes for SCE's grid, which includes:

   a. Performing analysis of transmission correct operations and mis-operations and documentation. For mis-operations, a root-cause analysis is performed and the resolution of the mis-operations is documented.

b. Performing analysis of distribution correct operations and mis-operations upon request. For mis-operations, a root-cause analysis is performed and the resolution of the mis-operations is documented.

c. Arc Flash Support to reduce incident energy values on distribution circuits by calculating and adding arc flash settings to protective relays.

d. Fast Curve Support by incorporating latest philosophies in protection system design to ensure public safety via reduction of the wildfire risk on circuits in the High Fire Risk Area (HFRA) while maintaining reliability.

6. Evaluating and selecting components, software, and systems to enable remote monitoring and operations of transmission and distribution facilities.

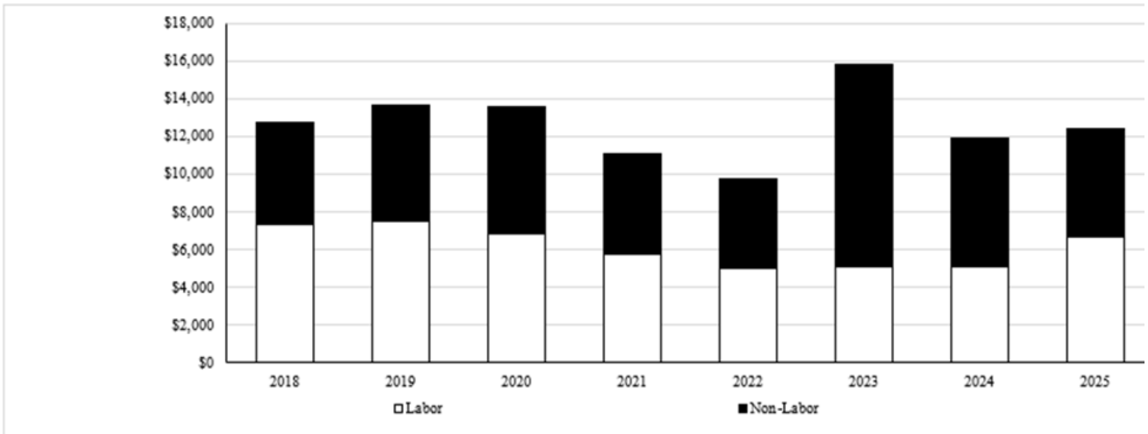
7. Providing training and knowledge transfer to keep up with the technical, equipment, and technology changes in our industry (e.g., 3-D engineering design modeling tools/software, etc.).

8. Engaging in support activities required to enable all of the engineering activities, including quality management for engineering work products, managing engineering standards and specifications, coordinating compliance with regulatory engineering standards and requirements, and management of engineering contract services.

b) <u>Scope and Forecast Analysis</u>

The recorded and forecast O&M expenses for Grid Engineering are shown below in Figure IV-36.

Figure IV-36
***Grid Engineering*[177]**
Recorded 2018-2022/Forecast 2023-2025
(Constant 2022 $000)



	Recorded					Forecast		
	2018	2019	2020	2021	2022	2023	2024	2025
Labor	$7,317	$7,526	$6,817	$5,752	$4,990	$5,072	$5,112	$6,694
Non-Labor	$5,414	$6,117	$6,758	$5,323	$4,769	$10,729	$6,783	$5,676
Total Expenses	**$12,731**	**$13,643**	**$13,575**	**$11,075**	**$9,758**	**$15,800**	**$11,895**	**$12,370**
Ratio of Labor to Total	57%	55%	50%	52%	51%	32%	43%	54%

(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-36 above, labor costs decreased each year from 2019 to 2022 due to organizational realignments, system planning project work deferred to future years, and vacant positions not being filled. One of the reasons that system planning project work was deferred was that the same skilled engineering resources complete Grid Engineering and customer-requested generator interconnection studies. There was a significant influx of customer-requested generator interconnection studies in 2021 and 2022, which temporarily required SCE to defer some Grid Engineering work until additional resources can be trained to complete this work.

[177] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 187-192 O&M Detail for Grid Engineering.

(b) **Non-Labor**

Non-labor expenses include costs for contract engineering work required to supplement work performed by SCE personnel. In addition, non-labor expenses include allocated overheads. Non-labor costs increased in 2019 and 2020 due to Protection Engineering and Substation studies and Real Time Digital Simulator Testing work previously performed by SCE being transitioned to contractors due to this work needing a specialized skill set. In 2021, non-labor costs begin to decrease because SCE had to adjust its normal operations and practices in an effort to mitigate risk of COVID-19 transmittal and spread; as such business training and associated travel was suspended. In addition, some projects were deferred and cancelled due to contractors having work restrictions in response to the COVID-19 pandemic. In 2022, costs continued to decrease due to contractor related work being further delayed as a result of extended contract negotiations and due to reduced travel for business training as this training remained online as opposed to in-person.

(2) **Basis for O&M Forecast**

SCE forecasts $12.4 million for Grid Engineering for Test Year 2025, which includes $6.7 million for labor and $5.7 million for non-labor.[178]

(a) **Labor**

SCE forecasts its 2025 Test Year labor expense by using a five-year average of recorded costs.[179] While SCE also considered using the 2022 Last Recorded Year as the basis for its Test Year forecast, SCE rejected this approach because the Last Recorded Year would not accurately reflect the level of spending SCE expects to see in 2025. As discussed above, the recorded expenditures for Labor in 2021 and 2022 were lower than in 2018-2020 due to vacancies and the significantly increased generator interconnection study work in this period, which required resources to spend more time supporting those efforts.[180] This was a near-term anomaly in response to the new work and thus does not reflect a reduced need for the Grid Engineering activity going forward. Using a five-year average thus provides a better forecast of labor expenses needed in the Test Year.

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[178] Included in the forecast development process are employee led efficiency savings related to reduced expenses for Subtransmission System Coordination Studies as a result of SCE personnel performing the studies as opposed to contractors. Please refer to Exhibit SCE-06, Vol. 03 for additional details.

[179] The forecast incorporates an adjustment to reflect changes made to SCE's Employee Compensation Program. This is addressed at SCE-06, Vol. 04.

[180] Refer to SCE-02, Vol. 11 Other Costs & Other Operations Revenue for Interconnection related activities.

(b) Non-Labor

SCE forecasts its 2025 Test Year non-labor expense by using a five-year average of recorded costs. Grid Engineering non-labor is variable and often emergent because this activity includes complex contractor studies that are each needed in response to a specific issue, such as system reliability or compliance. Such issues cannot always be predicted but need to be promptly addressed when they are identified. Using a five-year average as the forecast method accounts for the inherent variability in the need for these studies. This methodology is supported by D.89-12-057, and subsequently D.04-07-022, in which the Commission stated that if recorded expenses have significant fluctuations from year-to-year, or expenses are influenced by external forces beyond the utility's control, an average of recorded expenses is appropriate.

2. Load Side Support

a) Work Description and Need

Load Side Support is an SCE program that addresses issues that can arise as a result of the generation, transmission, and delivery of power to our customers. This program provides investigative services that extend beyond the revenue meter and include wiring and grounding inspections, power quality monitoring, and radio frequency interference measurements. SCE's Power Quality department personnel identify the cause of power quality and interference problems and may recommend solutions to customers and/or system owners.

The proliferation of microprocessor controllers within DERs, EVs, protective relays, appliances, and manufacturing equipment has increased the level of sensitivity customers have to momentary power system disturbances.[181] Power system faults, capacitor switching, and starting of large loads are common sources of disturbances that are addressed by this program. Electronic-based generation and motor control systems have also led to an increase in distortion of the 60-Hertz sinusoidal voltage supplied by the power system.[182] This steady-state phenomenon is referred to as harmonic distortion and results in overheating of motors and transformers, mis-operation of microprocessor controllers, and nuisance tripping of loads such as EV chargers and uninterruptible power supplies.

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[181] "IEEE Guide for Identifying and Improving Voltage Quality in Power Systems," in Institute of Electrical and Electronics Engineers (IEEE) Std 1250-2018 (Revision of IEEE Std 1250-2011) , vol., no., pp.1-63, 16 Nov. 2018, doi: 10.1109/IEEESTD.2018.8532376.

[182] "IEEE Standard for Harmonic Control in Electric Power Systems," in IEEE Std 519-2022 (Revision of IEEE Std 519-2014) , vol., no., pp.1-31, 5 Aug. 2022, doi: 10.1109/IEEESTD.2022.9848440.

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

Power Quality Advisors ensure the quality of power delivered to SCE's customers remains within industry recommended limits.[183,184] Corrective actions may include changes to the customer systems, SCE systems, or both. Recommendations provided to customers to reduce sensitivity to disturbances often include low-cost mitigation equipment and setting changes. Customers operating loads that interfere with the service provided to other customers may be required to install filters or equipment designed to minimize starting currents.

Power Quality Advisors also investigate causes of stray and contact voltage reported by customers or other utilities. Stray voltage results from the normal delivery or use of electricity that may be present between two conductive surfaces that can be simultaneously contacted by members of the general public or animals.[185] Stray voltage is not related to electrical faults but can be the result of electric or magnetic fields near transmission lines or from normal return current. These investigations may include testing of underground cabling and inspection of grounding systems owned by customers.

SCE employs contract lineman to perform investigations that reveal the nature of the electromagnetic interference and its cause. These employees recommend solutions to customers and, when needed, work with other SCE field personnel to perform corrective actions to comply with FCC regulations. Corrective actions on the SCE system may include washing or replacing insulators and tightening line hardware.

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[183] ANSI C84.1-2020, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz).

[184] "IEEE Standard for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems," in IEEE Std 1453-2022 (Revision of IEEE Std 1453-2015) , vol., no., pp.1-83, 27 Feb. 2022, doi: 10.1109/IEEESTD.2022.10051670.

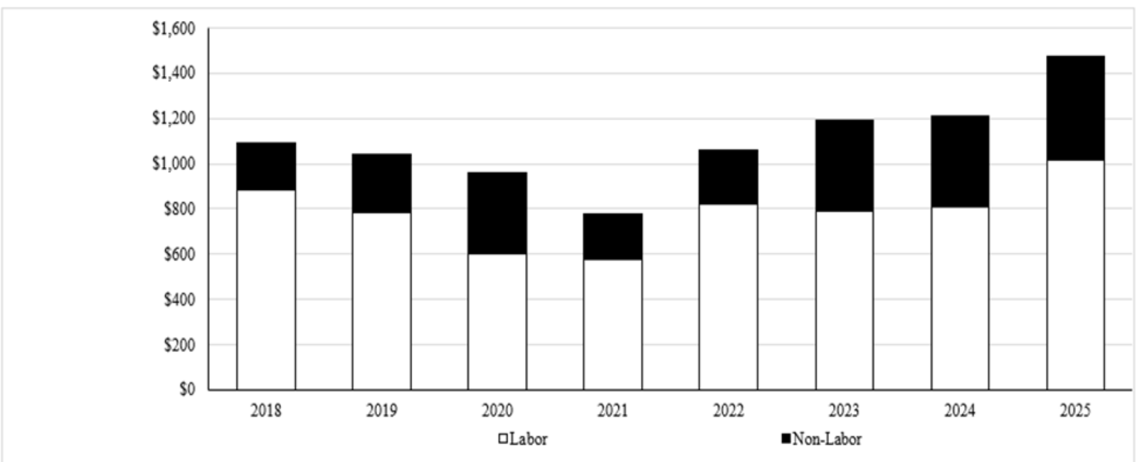
[185] "IEEE Guide to Understanding, Diagnosing, and Mitigating Stray and Contact Voltage," in IEEE Std 1695-2016 , vol., no., pp.1-117, 8 July 2016, doi: 10.1109/IEEESTD.2016.7508856.

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

b) <u>Scope and Forecast Analysis</u>

The recorded and forecast O&M expenses for Load Side Support are shown below in Figure IV-37.

Figure IV-37
Load Side Support[186]
Recorded 2018-2022/Forecast 2023-2025
(Constant 2022 $000)



	Recorded					Forecast		
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Labor	$886	$786	$604	$576	$821	$793	$807	$1,015
Non-Labor	$208	$256	$354	$201	$239	$402	$402	$460
Total Expenses	**$1,094**	**$1,042**	**$958**	**$777**	**$1,060**	**$1,195**	**$1,210**	**$1,475**
Ratio of Labor to Total	81%	75%	63%	74%	77%	66%	67%	69%

(1) <u>Historical Variance Analysis</u>

(a) <u>Labor</u>

Labor costs decreased from 2018 through 2021, primarily due to vacant positions going unfilled. Costs then increased in 2022 due to those vacant positions being filled.

186 Refer to WP SCE-02, Vol. 07 Bk. C, pp. 193-198 O&M Details for Load Side Support.

(b) Non-Labor

The need for contractors to perform supplement work or provide specialized skills varies year-to-year based on the volume and type of customer calls related to power quality concerns. From 2018-2020, non-labor costs increased due to the addition of two contract employees performing radio frequency interference investigations and the associated training, both classroom and on-the-job, for these contract employees that took place in 2019 and 2020. Costs then decreased in 2021 with the conclusion of training but remained close to the 2018 level due to the continuation of radio frequency interference investigations. Costs then increased slightly in 2022 due to the increased use of independent consulting services and increased vehicle operational costs.

(2) Basis for O&M Forecast

SCE forecasts $1.475 million for Load Side Support for Test Year 2025, which includes $1.015 million for labor and $0.460 million for non-labor.

(a) Labor

For the Test Year 2025 labor forecast, SCE started with the 2022 Last Year Recorded amount of $0.821 million because SCE forecasts baseline activities to continue at the 2022 level. SCE then made an upward adjustment of $0.194 million to account for an expected increase in the Power Quality workload and staffing in supporting State initiatives (e.g., carbon neutrality by 2045 and transportation electrification) and grid modernization. Power Quality concerns are driven by third-party activities and can vary year-over-year. The rapid growth along with the increased complexities of transportation and building electrification combined with the replacement of synchronous generation with inverter-based generation and DERs across the system has created new power quality issues on the electrical grid. To manage the increasing Power Quality concerns, SCE forecasts the need for two additional personnel to be in place before 2025.[187,188]

(b) Non-Labor

For the Test Year 2025 non-labor forecast, SCE started with the 2022 Last Year Recorded amount of $0.239 million because SCE forecasts baseline activities to continue at the 2022 level. SCE then made an upward adjustment of $0.221 million to account for the incremental external support that will be needed in the Test Year due to the increasing complexity of the

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[187] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 199-200 Load Side Support Forecast.

[188] The forecast incorporates an adjustment to reflect changes made to SCE's employee compensation program. Please refer to SCE-06, Vol. 04.

electromagnetic interference and power quality issues that must be addressed by the Power Quality department. This increasing complexity is driving an increased need for specialized investigation work performed by a third-party firm and contract employees for specialized engineering. Investigations are primarily in response to customer or system issues, therefore, the need for these external expert services can vary from year to year. The size of this adjustment accounts for that expected year over year variance. This level of funding—last year recorded plus the adjustment—is necessary for SCE to adequately respond to and resolve customer issues.[189]

[189] Refer to WP SCE-02, Vol. 07 Bk. C, pp. 199-200 Load Side Support Workpaper.