Decision **PROPOSED DECISION OF ALJ RIZZO AND ALJ SEYBERT**
(Mailed 7/28/2025)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) For Authority to Increase Its Authorized Revenues for Electric Service In 2025, Among Other Things, and to Reflect That Increase in Rates.	Application 23-05-010

DECISION ON TEST YEAR 2025 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

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Appendix A — List of Acronyms
Appendix B — Results of Operations 2025-2028
Appendix C — Updated Affordability Metrics

DECISION ON TEST YEAR 2025 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY

Summary

This decision approves a test year base revenue requirement of $9.664 billion for Southern California Edison Company (SCE). The adopted amount is a 12.61 percent increase over SCE's current authorized revenue requirement compared to SCE's requested 22.15 percent increase and reflects our careful assessment and determination of operating expenses and capital expenditures necessary for SCE to provide safe and reliable service at just and reasonable rates. The adopted 2025 revenue requirement shall become effective upon the filing of tariffs pursuant to the directives of this decision.

This decision also authorizes post-test year revenue requirement adjustments of $544 million for 2026 (a 5.63 percent increase), $522 million for 2027 (a 5.11 percent increase), and $447 million for 2028 (a 4.17 percent increase), along with the adoption of a post-test year ratemaking mechanism. These adjustments provide funds necessary for SCE to continue to provide safe and reliable service to customers beyond the test year, while providing SCE a reasonable opportunity to earn the rate of return as authorized by the Commission in Decision 24-10-008.

Based on the date of issuance of this decision, we direct SCE to implement the 2025 test year revenue requirement in rates beginning October 1, 2025, or as soon thereafter as it may be effected. Given the timing of this implementation, and in consideration of public comments regarding the impact of bill increases and affordability concerns, we find it reasonable to specify that the incremental revenue increase that has accrued from January 1, 2025 through September 30, 2025 shall be amortized over a twenty-four month period.

With this amortization, the estimated impact of the approved revenue requirement in 2025 is an average residential monthly bill increase of approximately $9.79 (or 9.1 percent) for California Alternate Rates for Energy (CARE) customers, and $15.52 (or 9.1 percent) for non-CARE customers.[1] Granting SCE's full request (assuming the same twenty-four month amortization period) would have resulted in an average residential monthly bill increase of $24.72 (or 14.4 percent) for CARE customers, and $15.59 (or 14.4 percent) for non-CARE customers in 2025.

A significant component of SCE's request in this application is for capital expenditures, particularly as it relates to mitigating wildfire risk. The impact of current capital expenditures on current revenue requirements may be limited and incremental, but the cumulative impact is powerful over time as the value of capital assets (including rate of return and cost of removal) is repaid by ratepayers. SCE requests approximately $5.104 billion in capital expenditures for wildfire mitigation from 2025-2028. We approve approximately $3.085 billion of total capital expenditures for wildfire mitigation during this time period, reflecting our judgement that the long-term benefits of these investments justify the costs. We also deny other notable portions of SCE's request for expenditures that SCE has not demonstrated are just and reasonable costs of safe and reliable service.

Appendix B to this decision contains the detailed results of operations tables that summarize the annual GRC revenue requirements approved in this

[1] The bill impacts are estimates for illustrative purposes only based on monthly residential customer usage of 500 kilowatt hours/month, current base revenue requirement of $8.478 billion, and current rates as of June 2025. The bill impacts do not include one-time memorandum account recovery addressed in Sections 39.5.

decision for 2025-2028. Appendix C to this decision contains updated affordability metrics associated with the authorized revenue requirements. The revenue requirements authorized in this decision do not include commodity costs of electricity procured for customers or costs of fuel used in generating electricity, which are the subject of a separate proceeding.

This proceeding is closed.

1. Background

Southern California Edison Company (SCE) provides electric service to more than 15 million California residents through residential, commercial, and industrial customer accounts.[2] SCE's service territory is located throughout central and southern California and includes approximately 200 incorporated communities as well as outlying rural areas.

In this General Rate Case (GRC) application,[3] SCE requests an authorized base revenue requirement of $10.483 billion to become effective January 1, 2025.[4] SCE's request represents a $1.901 billion, or 22.15 percent, increase over currently authorized base rates.[5] SCE requests additional base revenue requirement increases of $668.1 million (or 6.4 percent) in 2026, $748.6 million (or 6.7 percent) in 2027 and $732.3 million (or 6.2 percent) in 2028.[6] SCE contends that its request

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[2] Application at 1.

[3] In Phase 1 of a GRC proceeding, the Commission determines the utility applicant's electric system revenue requirements and addresses related issues. Phase 2 of the GRC follows a separate application and addresses marginal cost, revenue allocation, and rate design matters.

[4] Exhibit (Ex.) SCE-40 at 1; SCE Opening Brief (OB) at 2.

[5] Ex. SCE-40 at 2. Including one-time memorandum account recovery requests and sales-adjusted GRC revenue growth between 2024 and 2025 would result in an increase of $1.933 billion, or 22.52 percent (Ex. SCE-40 at 2; SCE OB at 2).

[6] Ex. SCE-40 at 8, Table II-3 (line 3); SCE OB at 2, Table I-1.

is required to fund the necessary costs for reliability, resiliency, and readiness to operate, inspect, maintain, support, or augment SCE's electrical grid and other vital infrastructure and support functions.[7]

Many parties to the proceeding reviewed SCE's application and oppose various requests or recommend adjustments.

1.1. Procedural Background

On May 12, 2023, SCE filed Application (A.) 23-05-010 for Authority to Increase its Authorized Revenues for Electric Service in 2025, among Other Things, and to Reflect that Increase in Rates (Application). SCE's Application also included a request to recover certain recorded expenditures being tracked in various memorandum accounts.

Protests to the Application were timely filed by the following parties: (1) Community Legal Services (CLS); (2) the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); (3) The Utility Reform Network (TURN); (4) Energy Producers and Users Coalition (EPUC); (5) Mussey Grade Road Alliance (MGRA); (6) Clean Power Alliance of Southern California (CPA); and (7) California Choice of Energy Authority (CalChoice). Responses were timely filed by the following parties: (1) Coalition of California Utility Employees (CUE); and (2) Small Business Utility Advocates (SBUA).

In addition, the following parties requested and were granted party status in the proceeding: (1) Center for Accessible Technology (CforAT); (2) Natural Resources Defense Council (NRDC); (3) Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (collectively, Sempra Utilities); (4) California City County Streetlight Association (CASLA);

[7] Application at 2-4.

(5) California Community Choice Association (CalCCA); (6) Joint Truck OEMs; (7) California Manufacturers & Technology Association (CMTA); (8) Federal Executive Agencies (FEA); (9) Agricultural Energy Consumers Association (AECA); (10) California Farm Bureau Federation (Farm Bureau); (11) California Metals Coalition (CMC); (12) Energy Users Forum (EUF); (13) TeraWatt Infrastructure, Inc. (TeraWatt); (14) Walmart, Inc. (Walmart); (15) California Large Energy Consumers Association (CLECA); (16) Tesla, Inc. (Tesla); and (17) Pacific Gas & Electric Company (PG&E).

On June 26, 2023, SCE filed a Reply to the Protests and Responses.

A prehearing conference was held on July 12, 2023, to determine the parties and discuss the scope of issues, categorization, schedule of the proceeding, and other procedural matters.

On September 5, 2023, the assigned Commissioner issued a Scoping Memorandum and Ruling (Scoping Memo) setting forth the scope of issues, need for hearing, schedule, and category.

Testimony was submitted into the record of this proceeding. On May 12, 2023, SCE submitted its testimony. On December 22, 2023, SCE submitted Supplemental Testimony.

On February 29, 2024, the following intervenors submitted testimony: (1) Cal Advocates; (2) CalCCA; (3) CUE; (4) EPUC; (5) CLECA, AECA, Farm Bureau, CMTA, CMC, EUF, and EPUC (collectively, Joint Ratepayers); (6) Joint Truck OEMs; (7) MGRA; (8) NRDC; (9) SBUA; (10) SDG&E; (11) TeraWatt; (12) Tesla; (13) TURN; and (14) Walmart.

On March 11, 2024, SCE submitted 2023 Record Data.

On April 15, 2024, Rebuttal Testimony was served by: (1) CUE; (2) Joint Ratepayers; (3) Joint Truck OEMs; (4) NRDC; (5) SBUA; (6) SCE; and (7) TeraWatt.

On June 7, 2024, SCE submitted its update testimony.

On January 4, 2024, the assigned Administrative Law Judges (ALJs) issued a ruling noticing public participation hearings (PPH) for this proceeding. The California Public Utilities Commission (Commission) held a total of six PPHs: two in-person PPHs in Long Beach on April 10, 2024, at 2:00 p.m. and 6:00 p.m., and four remote PPHs were on March 5, 2024 and March 20, 2024, at 2:00 p.m. and 6:00 p.m. on each day. The in-person and remote PPHs were held to provide SCE's customers with an opportunity to communicate directly with the Commission regarding the Application and SCE's proposed rate increases. The assigned Commissioner and at least one of the assigned ALJs attended all the PPHs.

Evidentiary hearings were held virtually from May 6, 2024, to May 23, 2024.

On July 1, 2024, the assigned ALJs issued a ruling adopting corrections to the Reporter's Transcript (RT) for the evidentiary hearings.

On July 11, 2024, the Commission issued a decision granting the joint motion to extend SCE's Wildfire Liability Customer-Funded Self-Insurance Program.

On July 15, 2024, the following parties filed Opening Briefs (OBs): (1) NRDC; (2) TeraWatt; (3) CUE; (4) MGRA; (5) CalCCA; (6) Cal Advocates; (7) SDG&E; (8) TURN; (9) Joint Truck OEMs; (10) SCE; (11) Joint Ratepayers; (12) EPUC; (13) Tesla; (14) Walmart; and (15) SBUA.

On August 5, 2024, the following parties filed Reply Briefs (RBs): (1) Joint Truck OEMs; (2) MGRA; (3) Cal Advocates; (4) TeraWatt; (5) SDG&E; (6) EPUC; (7) TURN; (8) SCE; (9) Joint Ratepayers; (10) CalCCA; (11) NRDC; (12) CUE; and (13) SBUA.

On October 2, 2024, the assigned ALJs issued a ruling to adopt procedures for the confidential production of computer model runs using SCE's Results of Operations (RO) Model to generate tables needed for decision support in this proceeding.

On October 4, 2024, SCE filed a motion to establish a 2025 General Rate Case Revenue Requirement Memorandum Account; the motion was granted by ruling on October 23, 2024.

At SCE's request, pursuant to Rule 13.14 of the Commission's Rules of Practice and Procedure (Rules),[8] the Commission held an oral argument on August 11, 2025, in order to provide parties the opportunity to address the Commission on the issues in this proceeding.

1.2. Submission Date

This matter was submitted on August 11, 2025, upon the conclusion of oral argument.

2. Evidentiary Standards and Burden of Proof

Public Utilities (Pub. Util.) Code Section 451[9] provides that "all charges demanded or received by any public utility . . . shall be just and reasonable." Pursuant to Section 454(a):

> a public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a

[8] SCE OB at 568.

[9] All subsequent section references are to the Public Utilities Code, unless otherwise specified.

showing before the commission and a finding by the commission that the new rate is justified.

It is well-established that, as the applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application.[10] The Commission has held that the standard of proof the applicant must meet in rate cases is that of a preponderance of the evidence.[11] Preponderance of the evidence usually is defined "in terms of probability of truth, *e.g.*, 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[12]

Although the utility bears the ultimate burden to prove the reasonableness of the relief it seeks and the costs it seeks to recover, the Commission has held that when other parties propose a different result, they too have a "burden of going forward" to produce evidence to support their position and raise a reasonable doubt as to the utility's request.[13]

Since the evidence and arguments in this proceeding are voluminous, the discussion in this decision focuses on the major points of contention and does not provide detailed summaries of the evidence and arguments for every issue. However, we have reviewed and considered the exhibits in this proceeding pertaining to each section, the evidentiary hearing transcripts, and all the arguments raised by the parties, in deciding the revenue requirements and related policy directives adopted in this decision. As a general matter, with

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[10] Decision (D.) 09-03-025 at 8; D.06-05-016 at 7.

[11] D.19-05-020 at 7; D.15-11-021 at 8-9; D.14-08-032 at 17.

[12] D.08-12-058 at 19, citing Witkin, Calif. Evidence, 4th Edition, Volume (Vol.) 1 at 184.

[13] D.20-07-038 at 3-4; D.87-12-067 at 25-26, 1987 Cal. PUC LEXIS 424, *37.

respect to individual uncontested issues in this proceeding, we find that SCE has made a *prima facie* just and reasonable showing, and adopt the proposal, unless otherwise stated.

With respect to any settlement agreement, pursuant to Rule 12.1(d), we will only approve settlements that are reasonable in light of the whole record, consistent with the law, and in the public interest. Proponents of a settlement agreement have the burden of proof of demonstrating that the proposed settlement meets the requirements of Rule 12.1 and should be adopted by the Commission.

3. PPHs and Correspondence

As noted above, the Commission held a total of six PPHs in this proceeding, including four remote PPHs and two in-person PPHs. The PPHs were held to provide SCE's customers with an opportunity to communicate directly with the Commission regarding the Application and SCE's proposed rate increases. The assigned Commissioner and at least one of the assigned ALJs attended all the PPHs.

Of the general public who spoke at the PPHs, almost all opposed SCE's proposed rate increase. Many speakers raised concerns that SCE's rates have increased year-over-year at a rate that is not sustainable, and that customers have no other option to meet their energy needs. Several speakers who were on assistance programs or on fixed incomes stated they were already struggling to make ends meet, and could not afford any rate increase. Others stated that although they do not qualify for low-income programs, they still struggle to pay utility bills. Some speakers opposed the increases due to already high rates for heating and cooling in communities with extreme temperatures, and raised health concerns for customers who are forced to forgo heating or air conditioning

to lower their energy bills. Many speakers also expressed concerns that the rate increase would primarily benefit SCE management and shareholders, and stated the Commission should prioritize customers over corporate profit.

Speakers who supported the proposed rate increase often cited the ongoing need for SCE's wildfire and climate-related mitigation efforts.

Several speakers expressed difficulty being able to communicate with an SCE representative, citing phone calls that were either unanswered or were subject to excessively long wait times. Some speakers indicated they did not have a computer, and could only communicate via telephone.

In addition to the comments at the PPHs, over 274 written public comments were submitted in this proceeding. Among the public comments received, almost 95 percent oppose SCE's proposed rate increase, while five percent support the proposed rate increase. Many of the written public comments reiterate concerns voiced during the PPHs, including that the proposed rate increase would be used to pay for high corporate salaries and shareholder profits, and that customers cannot afford higher rates, particularly customers who are low-income, retired, or on fixed incomes. Several comments expressed concern over SCE's mismanagement of its system, or assert that, despite prior rate increases, customers continue to receive poor service and be subject to power shutoffs. Among the public comments that support SCE's proposed rate increase, many focus on the need to deliver clean energy, mitigate wildfire risks, and make communities safer.

4. Policy

Now, we provide an overview of this GRC's policy. Generally, a GRC is a proceeding in which the Commission authorizes an investor-owned utility (IOU) to recover through rates the reasonable capital investment costs and annual

expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner.

California's large energy utilities are required to file a GRC application every four years with the Commission. This means they follow a four-year GRC rate case cycle.[14] The GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated "test year" as well as forecasts for three subsequent post-test years, or "attrition years." The Commission's decision is based on its extensive review of the test year (TY) and post-test year (PTY) forecasts.

For all its complexity, the Commission's decision in a GRC proceeding can be summarized into the following components: (1) authorized O&M expenses; (2) return on rate base; (3) depreciation expenses; and (4) taxes. These components result in the annual customer revenue requirement which the Commission adopts. The adopted revenue requirement consists of: (1) the forecast O&M expenses approved by the Commission; plus (2) the revenues the utility forecasts will be necessary to recover the costs of its capital investments during the test year; and (3) the utility's estimated tax obligations. The capital-related revenues are expressed as the sum of: (i) the depreciation expense associated with the capital assets in the rate base; and (ii) the return on the utility's rate base.

The general rate case proceeding is viewed as the embodiment of what is often described as the "regulatory compact."[15] This compact is viewed as a

[14] D.20-01-002 at 32.

[15] D.20-01-002 at 10-11.

contract between the utility's investors and its customers; as such, it establishes rights, obligations, and benefits for both sides of the bargain.[16] It is the role of regulatory bodies such as this Commission to ensure that both sides fulfill their respective obligations under this bargain.[17] Given the vastly different resources at the disposal of the utilities and their customers, it is up to the Commission to maintain the balance in outcomes between customers and shareholders to ensure safe, reliable service at just and reasonable rates.[18]

This proceeding, before the Commission, is SCE's GRC request. While acknowledging the financial request of its GRC, SCE asserts it has prioritized programs and activities that are necessary and prudent to protect customers and communities from public safety risks, maintain and improve customer service, and implement the state's public policy goals.[19] SCE attributes the most significant driver of incremental funding in this GRC cycle to service reliability to meet customers' growing demand for, and reliance upon, electricity.[20] SCE contends that customers have a growing demand for electricity that lights their homes and businesses, powers their cars, helps them work or study remotely, and enables them to stay connected.[21] SCE focuses on the following topics which predicate its GRC request: (1) reliability; (2) resiliency; (3) readiness; and (4) affordability.

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[16] D.20-01-002 at 10-11.

[17] D.20-01-002 at 11.

[18] D.20-01-002 at 11.

[19] SCE OB at 6.

[20] SCE OB at 6.

[21] SCE OB at 7.

First, with respect to reliability, SCE is seeking to return its Infrastructure Replacement programs back to traditional, previously-recorded levels.[22] In the 2021 GRC cycle, SCE had to temporarily reduce the scope of its Infrastructure Replacement programs in order to focus its resources on emergent, higher-risk wildfire mitigation work.[23] SCE seeks a return to the traditional and previously-recorded Infrastructure Replacement program levels due to aging infrastructure which SCE states is acute for grid components sited outside of high fire risk areas (HFRA).[24] Thus, SCE is seeking to resume Distribution Infrastructure Replacement activities to the level that SCE recorded in 2018.

Second, with respect to resiliency, SCE states its grid resiliency is focused toward developing and deploying needed programs to protect public safety and the integrity of the grid. In this Application, SCE requests additional levels of funding to continue to reduce the ignition risk in its service area, reduce the remaining wildfire risk on to its system, and further reduce the need for Public Safety Power Shutoffs (PSPS) with continued grid hardening.[25] Specifically, SCE seeks covering conductor, undergrounding assets on a targeted basis, and engagement in other grid hardening measures.[26] SCE also seeks to augment its physical and cyber security efforts to address the exponential growth in the number and sophistication of attacks on critical grid infrastructure.[27]

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[22] Ex. SCE-13, Vol. 1, Part (Pt.) 1, Chapters II and V.

[23] Ex. SCE-01, Vol. 1.

[24] Ex. SCE-02, Vol. 1, Pt. 1 at 14.

[25] SCE OB at 7.

[26] Ex. SCE-13, Vol. 01 at 4.

[27] Ex. SCE-15, Vol. 3 at 1-5.

Third, with respect to readiness, SCE seeks to address what it describes as the fastest electricity demand growth in decades by proposing investments that will ready the grid to support the widespread electrification and decarbonization needed to meet California's decarbonization goals.[28] In furtherance of this, SCE requests that the Commission adopt its supplemental transportation electrification growth forecast identified as the Transportation Electrification Grid Readiness (TEGR) forecast.[29]

Finally, SCE states that it recognizes that affordability and equity are central to all of its requests. SCE states that it recognizes the necessary investments it proposes to make the grid reliable, resilient, and ready are costs that are borne by customers.[30] SCE states it has looked for ways to save customers money, avoid cost increases, and gain efficiencies.[31] SCE contends that if the Commission adopts its clean energy investments, by the early 2030s, the average SCE household can expect to see a significant decrease in total energy bills due to the benefits of electrification.[32] In further support of its efforts towards affordability, SCE cites to a self-insurance model for wildfire liability risk, its Inspection Redesign Initiative, and its Operational Excellence Catalyst (OEC), which is an employee-led continuous improvement effort to deploy innovative ideas and drive process improvements across its enterprise.[33] SCE

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[28] Ex. SCE-13, Vol. 7 at 10-11.

[29] Ex. SCE-13, Vol. 7 at 20; *see also* Ex. SCE-02, Vol. 07 at 19-20.

[30] Ex. SCE-12 at 15-16; *see also* Ex. SCE-01, Vol. 01 at 32-33.

[31] SCE OB at 9.

[32] SCE OB at 11.

[33] SCE OB at 8.

states that its OEC has resulted in approximately $75.752 million of O&M savings and $79.070 million of capital savings in its 2025 Test Year to customers.[34]

Many consumer, environmental, and industry advocacy organizations support or contest elements of SCE's request. For example, TURN and Cal Advocates challenge the scope of SCE's wildfire grid hardening, its TEGR forecast, its Distribution Infrastructure, Distribution Maintenance, and Capital-related expenses, and its Grid Modernization, Grid Technology, and Energy Storage programs. TURN acknowledges that a substantial portion of SCE's request is tied to activities or costs that are essential for safety, reliability, and the advancement of California climate policy. However, TURN also asserts that SCE's request must be scrutinized with the recognition that there may be conflicting interests between shareholders and ratepayers and every dollar spent must consider the constraints of customer affordability.[35]

First, TURN challenges SCE's contention that if the Commission adopts SCE's clean energy investments, by the early 2030s, the average SCE household can expect to see a significant decrease in total energy bills. For example, TURN proposes that the Commission should reject SCE's $1,031 million capital expenditure forecast for 2023-2028 associated with the TEGR plan given what it calls a flawed modeling approach used by SCE to develop the TEGR and significant locational and technical uncertainties associated with load forecasting, particularly for new technology groups such as medium- and heavy-duty electric vehicles.[36]

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[34] Ex. SCE-18, Vol. 1, Appendix B, OE Program 2025 GRC Rebuttal Savings and WPSCE-06, Vol. 3 at 204.

[35] TURN OB at 36.

[36] Ex. TURN-07E at 6-23.

TURN also challenges SCE's Overhead Conductor Program which is part of its Infrastructure Replacement Program. TURN contends that SCE's request for funding for this program should be denied because it would be unlikely to achieve the projected reliability and safety benefits.[37] With respect to SCE's Underground Cable Replacement Program, TURN believes that the Commission should adopt 800 miles of replacement, rather than SCE's proposed 1,600 miles, because a reduced number of miles achieves 60-70 percent of the safety and reliability benefits while also reducing costs borne by ratepayers.[38]

Additionally, TURN challenges SCE's growing use of machine learning-based modeling methods. TURN submits that the machine learning models SCE relies upon to support its infrastructure replacement proposal limit the insight of intervenors to scrutinize the models' inputs and results.[39] In other words, TURN argues that SCE's machine learning models are black boxes.[40]

For its part, Cal Advocates also proposes reductions and downward adjustments to SCE's estimated forecasts and capital expenditures.
Cal Advocates argues that SCE seeks unnecessary funding based on the premise that its proposed improvements are urgently needed to prepare the grid for widespread electrification and decarbonization, which are necessary to meet California's greenhouse gas (GHG) reduction goals. However, Cal Advocates' position is that the state has been preparing for its GHG reduction systematically for some time now, and SCE has not demonstrated a necessary emergency

[37] Ex. TURN-05-E at. 41-45.

[38] TURN OB at 83.

[39] TURN OB at 211.

[40] TURN OB at 211.

requiring such increased costs that must be placed on ratepayers.[41] Thus, Cal Advocates proposes reductions to the following SCE programs: (1) Distribution Infrastructure Replacement Program;[42] (2) Distribution Inspections and Maintenance Program;[43] (3) Transmission Grid Program;[44] (4) Substation Program;[45] and (5) Energy Procurement and Generation O&M expenses and expenditures for 2023-2025.[46] Cal Advocates contends that SCE fails to justify the costs of these programs and simply identifies policy implementations as the driver of these costs.[47] In short, Cal Advocates contends that SCE overstates the need for many of these capital expenditures and forecasts. Cal Advocates states that SCE has not met its burden to increase costs during this TY.[48]

At the same time, Cal Advocates also opposes SCE's expense forecasts. In support of its opposition, Cal Advocates asserts that some of SCE's expense forecasts are substantially and unreasonably out of proportion to what SCE spent for the same work since the last GRC. Finally, throughout its testimony, Cal Advocates states it identified projects that will not be used and/or be useful during the GRC cycle and/or projects that are not well-planned, or are not

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[41] Cal Advocates OB at 4.

[42] Ex. CA-03 at 12.

[43] Ex. CA-03 at 36-37.

[44] Cal Advocates OB at 75-77.

[45] Cal Advocates OB at 85-92.

[46] Cal Advocates OB at 303-322.

[47] Cal Advocates OB at 4.

[48] Cal Advocates OB at 4.

supported by historical data, technical experience, or sound economic judgment.[49]

In response to TURN and Cal Advocates assertions regarding the TEGR, several intervenors support SCE's load growth proposals, citing California's electrification and decarbonization goals as the basis for the Commission to adopt the TEGR. Specifically, NRDC supports SCE's Load Growth forecast, and supports the TEGR.[50] NRDC asserts that SCE's TEGR is compliant with California's electrification and decarbonization laws.[51] NRDC states that SCE is required by the state to take into account policies and regulations requiring transportation electrification[52] and because the 2020 IEPR did not take those policies and regulations into account, SCE needed to look to alternative forecasts for compliance.[53] NRDC argues that SCE must propose grid upgrades in the GRC to comply with California policy to fully electrify light, medium, and heavy-duty vehicles, and buildings through 2045.[54] NRDC states that upgrades are likely needed due to baseline load growth alone, even if transportation electrification and building electrification are removed from load growth forecasts.[55]

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[49] Cal Advocates OB at 5.

[50] NRDC OB at 11.

[51] NRDC OB at 12.

[52] NRDC OB at 12.

[53] NRDC OB at 12.

[54] Ex. NRDC-01 at 4.

[55] Ex. NRDC-03 at 19.

Walmart asserts that SCE has not included enough capacity to fully support the state's transportation electrification projections.[56] Walmart states that given the consumer electric vehicle sales and electric vehicle fleet deployment growth in SCE's region, SCE's forecasted TEGR capital expenditures are likely too low.[57] Walmart asserts that the Commission should ensure sufficient funding for new electric vehicle charging deployments.[58]

Terawatt asserts that SCE's TEGR forecast does not go far enough. First, Terawatt asserts that SCE's load growth forecast does not consider policies and incentives that further increase demand for medium- and heavy-duty electric vehicle adoption that were enacted since the development of the TEGR.[59]

The Joint Truck OEMs also support SCE's TEGR forecast. The Joint Truck OEMs argue that SCE's TEGR forecast is reasonable in response to new regulations and other developments that occurred after SCE's base forecast was set.[60] The Joint Truck OEMs assert that the Commission's approval of SCE's request to upgrade the grid in support of charging electric medium- and heavy-duty vehicles is critical to ensuring that SCE has sufficient grid capacity to support the charging stations needed to fuel the deployment of medium- and heavy-duty commercial zero emission vehicles.[61] The Joint Truck OEMs contend that delays in energization due to requests for service requiring grid upgrades

[56] Walmart OB at 8.

[57] Walmart OB at 8.

[58] Walmart OB at 8.

[59] Terawatt OB at 11.

[60] Joint OEMs OB at 7.

[61] Ex. Joint Truck OEMs-01 at 7.

exceed the charging infrastructure developer's timeline for service need.[62] The Joint Truck OEMs also point out that TURN's and Cal Advocates' analysis of vehicle fleet charging is incongruent with actual business functions and critical business needs.[63]

Tesla argues that SCE's TEGR provides a reasonable basis for expected infrastructure need.[64] Tesla states that the use of the Integrated Energy Policy Report (IEPR) load growth forecast for infrastructure planning is problematic because of the significant lag time between when the IEPR forecast is generated and when the Distribution Planning Process (DPP) or GRC are informed by that IEPR vintage.[65] Tesla reasons that this lag has created major issues for grid planning during the early years of the 2020s when California transitioned from flat load growth to significant load growth driven by a combination of consumer demand for electric vehicles and the state's newly enacted transportation electrification policies.[66]

MGRA highlights several policy issues that it believes the Commission will need to address regarding grid hardening in response to increase wildfire risk. In particular, MGRA asserts that: (1) SCE's Integrated Wildfire Mitigation Strategy (IWMS) has not been demonstrated to be a risk model, though in some cases it provides a heuristic that compensates for flaws in SCE's MARS wildfire risk model; and (2) alternatives to undergrounding exist which may result in significant ratepayer savings.

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[62] Ex. Joint Truck OEMs-01 at 7-9.

[63] Joint Truck OEMs OB at 11-12.

[64] Tesla OB at 6.

[65] Tesla OB at 6.

[66] Tesla OB at 6.

For its part, SCE asserts that rates have increased in recent years due to increased safety and reliability spending and not unchecked spending. SCE asserts that its rates are appropriately and inextricably tied to its cost of service, and SCE's cost of service — service that provides significant benefits related to safety, reliability, resiliency, and clean energy to customers — has increased.[67]

SCE contends that arbitrarily keeping rate increases lower than the rate of growth of household incomes notwithstanding these rising costs would compromise SCE's ability to provide safe and reliable service, which is not in customers' interests.[68] First, SCE contends that TURN's arguments against the resumption of traditional levels of infrastructure replacement spending are erroneous because the record is replete with exhaustive evidence that SCE temporarily reallocated resources from infrastructure replacement work to urgently focus on mitigating the near-existential threat that wildfires posed to the safety and well-being of California communities.[69]

Second, SCE asserts that to adequately prepare for the continued acceleration of load growth driven by its customers' transportation electrification adoption, SCE has undertaken planning analyses for this GRC utilizing the TEGR, with the intent of identifying and developing grid infrastructure plans that ready the grid for this imminent growth of energy demand.[70] SCE contends that TURN and Cal Advocates present flawed arguments in opposition to the

[67] Ex. SCE-12 at 29.

[68] SCE RB at 5.

[69] Ex. SCE-13, Vol. 1 at 4-6; *see also* Ex. SCE-02, Vol. 1, Pt. 2, at 12-14.

[70] SCE OB at 111.

TEGR, particularly the wait-and-see approach which SCE asserts is contrary to state policy.[71]

SCE is required by law to "promote the safety, health, comfort, and convenience of its patrons, employees, and the public" while including only "just and reasonable" charges in its rates.[72] A fundamental challenge in many disputed areas of this proceeding is to reach an outcome consistent with these two, often competing, objectives. While this is a familiar challenge present in numerous past GRCs, the rate impacts are real and will be uniquely felt by customers.

At the same time, the increasing threat of catastrophic wildfires has made wildfire mitigation a high priority for the state and this Commission as well as grid resiliency and grid reliability. Our review of SCE's wildfire-related and grid resiliency and reliability expenses is aided both by the robust party participation throughout this proceeding, as well as the risk-based decision-making framework SCE incorporates throughout its GRC application and testimony. The approved funds in this decision are significant, covering a diverse portfolio of mitigations to ensure ignition risk reduction is supported in wildfire prone areas. However, this decision also makes substantial reductions to SCE's forecasts, focusing on measures that are cost-effective and that target SCE's highest risk circuits.

The amounts authorized in this decision are tied to SCE's individual requests for proposed programs and activities, and reflect our assessment of the operating expenses and capital expenditures necessary for SCE to provide safe

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[71] SCE OB at 125-126.

[72] Pub. Util. Code Section 451.

and reliable service at just and reasonable rates. We have considered the record and, where appropriate, we make substantial reductions to the activities or costs that TURN, Cal Advocates, and others argue could have been excluded from this GRC request. We discuss our reasoning regarding the issues presented before the Commission, below.

5. Affordability and Equity

5.1. Affordability Metrics

5.1.1. SCE's Metrics

SCE presents several metrics to assess the affordability of SCE's rates, including: (1) SCE's rates compared to other major electric IOUs in California; (2) share of wallet analyses based on how a customer's total spending on energy (including electricity, gasoline, and natural gas) is allocated;[73] (3) energy burden, which is defined as the percentage of a household's annual income that is spent on electricity;[74] and (4) the Commission-adopted Affordability Ratio (AR) and Hours at Minimum Wage (HMW) metrics.[75]

SCE's data shows its bundled system average rate (SAR) has been below PG&E's and SDG&E's bundled SARs from 2016 through January 1, 2023.[76]

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[73] Ex. SCE-07, Vol. 4 at 5.

[74] Ex. SCE-07, Vol. 4 at 7.

[75] The AR is the ratio of essential utility service bills to non-disposable household income (*i.e.*, household income after removing costs for housing and other essential utility services). The Hours at Minimum Wage metric seeks to describe the hours of work necessary for a household earning minimum wage to pay for essential utility service charges. (D.22-08-023 at 16-30; Ex. SCE-07, Vol. 4 at 11-13).

[76] The bundled (*i.e.*, the subset of customers that receive both generation and energy delivery services from SCE) SAR is a utility's authorized revenue requirement allocated to bundled customers divided by bundled kilowatt hours of sales. (Ex. SCE-07, Vol. 4 at 10-11).

SCE's share of wallet analyses show the near-term increase in electricity bills to enable widespread electrification will be accompanied by decreases in gasoline bills due to the switch from gasoline vehicles to electric vehicles (EVs).[77] These analyses also show that by the early 2030s, the average household in SCE's service territory — including EV adopters and non-EV adopters — can expect to see a significant decrease (>10 percent) in total energy bills despite an increase in electricity bills.[78]

SCE evaluates the estimated change in energy burden (from current electric bills to projected 2028 electric bills) grouped by income status using the conservative assumption that household income will remain static from 2023-2028. Within these parameters, SCE estimates that by 2028, on average, the electric energy burden will increase by one percent for the average SCE California Alternate Rates for Energy (CARE) and non-CARE customer.[79] SCE also presents energy burden calculations grouped by usage to evaluate the affordability impact on essential usage.[80] The results indicate that from 2023-2028, low usage households (usage from 0 to 399 kilowatt-hour (kWh)/month) will see an increase in energy burden of less than half of one percent over the four-year period.[81]

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[77] Ex. SCE-07, Vol. 4 at 5.

[78] Ex. SCE-07, Vol. 4 at 3-7.

[79] Low-income customers that are enrolled in the CARE program receive a 30-35 percent discount on their electric bill. (*See* Pub. Util. Code Section 739.1.)

[80] Essential usage (also referred to as the baseline amounts of electricity) is generally 60 percent of the average household usage in a given climate zone. (Ex. SCE-07, Vol. 4 at 11).

[81] Ex. SCE-07, Vol. 4 at 7-10.

Finally, SCE calculated the AR and HMW metrics, which focus on the changes in cost over time for essential amounts of electricity usage by multiplying the number of baseline kWh by the utility's baseline rate per kWh. The AR50 and AR20 display the AR for a representative hypothetical household in the middle (50th percentile) and lower-end (20th percentile), resource-wise, compared to others in a community, and are calculated using the Commission's Affordability Ratio Calculator.[82] For AR20, the results show an increase by 0.4 percent on average from 2023-2028 for CARE customers and 0.6 percent for non-CARE customers, indicating that the AR is relatively unchanged over the course of the GRC cycle. The AR50 shows a 0 percent increase from 2023-2028 for both CARE and non-CARE customers. Lastly, the average HMW metric increased a total of 1.2 hours and 0.8 hours from 2023-2028 for non-CARE and CARE customers, respectively.[83]

5.1.2. Other Metrics and Data

TURN presented data showing that the cumulative rate of general inflation over 2019-2023, as measured by the Consumer Price Index-Urban (CPI-U), was roughly 21 percent for the Los Angeles area and 18 percent for California overall, compared to the nearly 46 percent cumulative increase in SCE's system average bundled electricity rate over this same time period.[84] TURN also points to SCE's historical AR metrics, which show that current AR levels have decreased by an

[82] The Affordability Ratio Calculator used for all calculations in SCE's testimony is the 2020 Affordability Ratio Calculator. (Ex. SCE-07, Vol. 4 at 12).

[83] Ex. SCE-07, Vol. 4 at 11-17.

[84] Ex. TURN-02E at 3-4; Ex. SCE-07, Vol 4, Figure II-2 at 11.

average of more than 40 percent for AR20 and nearly 40 percent for AR50 customers since 2022.[85]

Using Self-Sufficiency Standard (SSS) calculators,[86] TURN presented data indicating that CARE and FERA "Assistance Gaps," which TURN describes as households that lack sufficient income to pay all household costs timely each month but earn too much to qualify for low-income energy subsidy programs, have widened since 2018. TURN also compared SSS to the median income in each county in SCE's service territory, with results indicating that, even at middle-income levels, there is little margin in household budgets to absorb rate increases that are higher than inflation.[87]

Joint Ratepayers present data showing that the gap between SCE's average rates and those of utilities in neighboring states has grown from a 15 percent premium in 1990 to over 200 percent in 2023. Joint Ratepayers also present data showing that California electric rates for industrial sector customers are approximately 2.5 times the average industrial sector rates of neighboring western states, while the industrial sector's annual statewide energy consumption within SCE's service territory declined 19 percent from 1990 through 2022.[88]

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[85] Ex. TURN-02E at 24.

[86] SSS Calculators are bottoms-up, budgetary estimates of the level of household income necessary to pay all household costs without the need for any public assistance program. The SSS income is frequently greater than the highest income qualifying for CARE or Federal Electric Rate Assistance Program (FERA), which are set at 200 percent and 250 percent of the state poverty level, respectively. (Ex. TURN-02E at 13).

[87] Ex. TURN-02E at 14; TURN OB at 30-33.

[88] Ex. Joint Parties-01 at 8-14.

5.2. Parties' Positions

SCE states affordability was a key factor SCE assessed when proposing the investments in this GRC, and that any affordability assessment must also account for why SCE is incurring the costs, the objectives SCE is trying to achieve, and the value that SCE's proposed scope of work will provide to customers. SCE also asserts near-term investments to electrify the economy and support the adoption of clean energy technologies, including investments to support transportation electrification (TE), are vital to facilitate future reductions in overall energy costs for SCE customers and to improve local air quality and reduce GHG emissions, particularly in disadvantaged communities. Lastly, SCE asserts numerous metrics support the affordability of SCE's request which, when considered collectively, demonstrate SCE's requests in this GRC will not unduly impact SCE's customers' ability to pay for essential electricity service.[89]

TURN highlights the disproportional increase in SCE's system average bundled electricity rate compared to the cumulative inflation rate for the years 2019-2023, and states that, based on SCE's request, by 2028 SCE's base revenues will have increased by nearly 70 percent cumulatively since 2022, with typical bills that are expected to reach $300 per month in some hot climates for non-CARE customers and more than $200 per month even with the CARE subsidy. TURN argues essential electricity bills calculated using baseline residential usage are already currently unaffordable for many in SCE's service territory and, all other things being equal, that a revenue increase of the magnitude requested by SCE is likely to negatively impact affordability for residential customers. TURN also critiques SCE's energy burden and share of

[89] Ex. SCE-07, Vol. 4 at 2-3; Ex. SCE-12 at 5-156; SCE OB at 9-19.

wallet analyses, and states that SCE's AR metrics show a history of steady decrease in affordability for both AR20 and AR50, with current and projected AR20 and HMW values substantially higher than the four percent guideline targeted in the low-income Percent of Income Pilot Program as well as the five percent energy burden threshold considered as a guideline in past Commission deliberations.[90]

TURN asserts that roughly 350,000 of SCE's low-income customers are not receiving support from the CARE or FERA programs, even though these customers are eligible, while many more customers fall through the CARE/FERA "Assistance Gaps." TURN also asserts that, due to expected federal tax depreciation adjustments, SCE's rising capital spend obscures the full price tag during the early years, only to exacerbate the affordability crises later. Lastly, TURN asserts utility bill unaffordability increases the likelihood of homelessness, and asserts SCE has not met its burden to establish that the TEGR supplemental portion of SCE's load growth forecast is necessary and reasonable. TURN also asserts TEGR load growth projects benefit those private companies the distribution infrastructure upgrades are being made on behalf of, while harming families who struggle to pay their electric utility bills.[91]

Based on the above, TURN asserts the Commission must "not just address, but also *arrest* current trends of rising electricity rates well in excess of the growth of household incomes, unprecedented capital spending levels, and the proliferation of revenue adjustments."[92] TURN recommends the Commission

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[90] Ex. TURN-02E at 17-27; TURN OB at 27-29 and 40-44.

[91] Ex. TURN-03 at 3-9; TURN OB at 30-39, 47-57.

[92] TURN OB at 28.

find that current levels of energy rates and bills are not affordable for many low-income customers, and that authorizing SCE's GRC requested increases will decrease affordability. TURN also recommends the Commission only approve costs that SCE has demonstrated are both necessary and affordable for customers, and that disconnection caps be maintained indefinitely.[93]

Cal Advocates states the importance of affordability cannot be overstated, particularly in the current economic environment, and recommends the Commission reject revenue increases that are not justified or that do not provide at least minimal benefits to ratepayers. Cal Advocates also recommends the Commission consider SCE's requests in an equitable way to all communities.[94]

Joint Ratepayers contend that SCE's application threatens to worsen affordability challenges and high electricity rates, particularly when compared to neighboring western states, and will further debilitate vital industries operating in California. Joint Ratepayers also warn that SCE's GRC request will deter customers from making near-term EV and other electrification project purchasing decisions, hindering state-wise electrification.[95]

MGRA asserts the rate increases required to implement massive wildfire mitigation programs may be approaching the level where they are impacting public health, especially for the poorest and most vulnerable.[96]

SBUA notes that SCE's testimony does not discuss small commercial customer affordability, and recommends SCE be required to adopt a small

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[93] TURN OB at 28-30, 33-35, 39, and 46-47.

[94] Cal Advocates OB at 5-8.

[95] Ex. Joint Ratepayers-01 at 8-27; Joint Ratepayers OB at 16-27.

[96] Ex. MGRA-01 at 99; MGRA OB at 17-20.

business affordability metric in order to capture the impact of utility rates on small commercial ratepayers.[97]

In response, SCE asserts: (1) the anticipated change in electric-only energy burden from 2023-2028 is small, and TURN's critiques of this metric are misplaced; (2) the AR metrics are meant to compare existing revenues to proposed revenues, while TURN fails to provide context around the reasons SCE's rates have increased since 2020; (3) TURN misuses the HMW metric by turning it into an income statistic and using average usage bills rather than essential usage bills, which inflates the result; (4) TURN's observations about a CARE/FERA "Assistance Gap" are not directly relevant to SCE's request; (5) SCE provided the affordability metric information required by D.22-08-023, which does not include an affordability metric for small business customers; (6) MGRA's assertion that rate increases are tied to reduced life expectancy is unsubstantiated; (7) TURN's speculation that SCE's rates are a direct contributor to the homeless crisis is inappropriate; and (8) TURN mischaracterizes the impact of federal tax depreciation on customer rates.[98]

In response to assertions that increasing electric rates will undermine the state's electrification and climate goals, SCE provides the following arguments: (1) there are electric rates and solutions available that provide significant fuel savings benefits to owners of EVs, compared to gasoline costs; (2) increasing gasoline prices will have a much bigger impact on EV adoption rates than the increased electric rates requested in SCE's GRC; (3) prospective EV adopters have noted lower maintenance costs and reduced GHG and local air pollution

[97] SBUA OB at 7-9.

[98] Ex. SCE-12 at 6-12; SCE OB at 11-15.

emissions as major factors for choosing EVs; and (4) any challenge to electrification posed by the cost of these investments is outweighed by the challenge that would be posed by failing to ensure a reliable grid that is ready to support electrification.[99] SCE and NRDC also argue that vulnerable front-line communities (communities near freeways, refineries, and other pollution sources) will receive air quality benefits from the electrification enabled by the proposed load growth projects.[100]

5.3. Discussion

The issue of the affordability of utility services is a central focus and concern for the Commission. As discussed above, the Commission has a mandate to ensure it only authorizes costs that are just and reasonable and necessary for the provision of safe and reliable service. The Commission has emphasized that, "a key element of finding a charge or rate just and reasonable is whether that charge or rate is affordable."[101] Section 382(b) states "recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures." Further, Section 739(d)(2) directs that the Commission "shall ensure that rates are sufficient . . . to recover a just and reasonable amount of revenue . . . while observing the principle that electricity and gas services are necessities, for which a low affordable rate is desirable."

[99] Ex. SCE-12 at 15-33; SCE OB at 16-24.

[100] SCE OB at 13-15; NRDC OB at 7-9.

[101] D.19-05-020 at 11.

In July 2018, the Commission instituted Rulemaking (R.) 18-07-006 to develop a common understanding and methods and processes to assess, consistent with Commission jurisdiction, the impacts on affordability of individual Commission proceedings and utility rate requests (Affordability Rulemaking). As part of the Affordability Rulemaking, the Commission adopted certain affordability metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential electricity, gas, water, and communications utility services in California, and directed electric and gas utilities to include the AR and HMW metrics in applications that seek to increase revenues by at least one percent.[102]

In compliance with D.22-08-023, SCE included the required AR and HMW metrics and related data (Areas of Affordability Concern, essential usage bills, and average usage bills) with its direct testimony. These metrics are based on the relevant usage data available when filing the application, and no party challenged the validity of SCE's AR and HMW calculated values.

The Commission has defined affordability as "the degree to which a representative household is able to pay for an essential utility service charge, given its socioeconomic status."[103] At the same time, the Commission has held that the definition of what constitutes affordability of essential utility services is not absolute, and has emphasized the assessment of the relative impacts of affordability over time to aid the Commission in its decision-making as it evaluates utilities' requests with rate implications.[104] Although there are no

[102] D.22-08-023 at 58-60.

[103] D.20-07-032 at 9.

[104] D.20-07-032, Conclusion of Law 32; D.22-08-023 at 50.

established thresholds as to when a rate becomes unaffordable, it is undisputed that SCE's requested revenue increase would result in rates over this GRC period that are relatively more unaffordable than in the recent past. SCE's requested TY revenue increase of approximately 22.5 percent would be a substantial increase for customers to absorb at one time.[105] The AR20 and HMW metrics SCE presents in this proceeding also show a relative decline in the projected affordability during the 2025 TY.

Moreover, we are mindful that SCE's GRC request comes at a time when recent, cumulative utility rate increases have far outpaced general inflation. TURN presents evidence that household incomes for Californians, particularly low-income Californians, have not kept pace with inflation or the rise in SCE's rates and bills. TURN also presents evidence that segments of the population are already struggling to pay bills for essential expenses, including segments of the population that are below income thresholds for a family to achieve a modest but adequate standard of living but are not eligible for utility assistance programs. These sentiments were also shared by many members of the public both at the PPHs and in written public comments submitted to the Commission.

Some of the affordability issues raised by intervenors are outside the scope of this proceeding (*e.g.*, eligibility thresholds for CARE/FERA, disconnection policies, the establishment of a small business affordability metric).[106] Others,

[105] SCE OB at 2.

[106] As discussed in D.24-12-074, the development of affordability metrics for non-residential customers is better considered and addressed in the Affordability Rulemaking. (D.24-12-074 at 41-42).

including claims that SCE's rates are connected to homelessness,[107] and that utility rate increases are tied to reduced life expectancy,[108] lack sufficient evidentiary support. Moreover, we recognize that affordability issues are also driven by factors such as wages not keeping pace with the costs of housing and other essential utility and non-utility expenses.

However, given SCE's current and proposed rate levels, and considering our statutory obligations, we agree with intervenors that customer affordability is a critical factor to consider in this proceeding, and find the data and analysis presented by the parties to be a useful backdrop against which to evaluate SCE's individual GRC requests. At the same time, we are also mindful that it is also in the public interest to ensure that the utility has adequate funding to safely operate and maintain its infrastructure and make necessary investments in safety and reliability. Many of SCE's requests were vigorously litigated by the parties, including SCE's proposed TEGR load growth forecast and wildfire capital expenditures, creating a robust record upon which to evaluate SCE's requests. We have carefully reviewed the record within this context and deny or adjust downward SCE's requests that we find are not adequately justified and would not result in just and reasonable rates.

6. Risk-Informed Strategy and Business Plan

In D.14-12-025, the Commission adopted a new risk-based decision-making framework for future GRCs to "assist the utilities, interested

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[107] TURN's primary evidence for its attempt to tie utility rates to homelessness is a December 2020 study in San Diego that has not been entered into the record in this proceeding for the truth of the matters asserted therein. (Ex. TURN-311; RT, Vol. 11 at 1098:13-21).

[108] In testimony, MGRA acknowledges the evidence it presents in this proceeding concerning the potential health effects from SCE's rate increase on health and safety is not conclusory, and that it can be subject to a wide range of valid criticisms. (Ex. MGRA-01E at 99-100).

parties and the Commission, in evaluating the various proposals that the energy utilities use for assessing their safety risks, and to manage, mitigate, and minimize such risks."[109] For the large energy IOUs, this primarily takes place through the filing of their Risk Assessment Mitigation Phase (RAMP) submission. The RAMP submission is designed to be integrated with a utility's GRC filing, and provides an assessment of the utility's top safety risks as well as how the utility plans to manage, mitigate, and minimize those risks through its GRC funding requests.[110] The Commission has continued to refine the risk-based decision-making framework and related requirements for inclusion in each utility's RAMP submission through numerous subsequent decisions.[111]

On May 13, 2022, SCE filed its RAMP report in A.22-05-013 (2022 RAMP Report), and subsequently integrated its RAMP risk assessment work within its 2025 GRC Application and testimony.[112] The 2022 RAMP Report examined and prioritized safety risks to SCE's customers, employees, contractors, and the company as a whole. The following top nine safety risks were identified through SCE's 2022 RAMP Report: (1) wildfire/Public Safety Power Shutoffs; (2) contact with energized equipment; (3) underground equipment failure; (4) seismic; (5) physical security; (6) cyber attack; (7) hydro dam failure; (8) employee safety; and (9) contractor safety.[113] The risks in SCE's 2022 RAMP Report are substantially similar to the top risks identified in SCE's 2018 RAMP

[109] D.14-12-025 at 4.

[110] D.14-12-025 at 38.

[111] *See* D.16-08-018, D.18-12-014, D.21-11-009, D.22-10-002, D.22-12-027, and D.24-05-064.

[112] Ex. SCE-01, Vol. 2 at 6-20; D.23-11-007 at 3.

[113] Ex. SCE-01, Vol. 2 at 7-8.

submission;[114] however, SCE's 2022 RAMP Report evaluates risk at a much more granular level.[115] In this GRC, SCE proposes programs and investments that correspond to the controls identified in SCE's 2022 RAMP Report to mitigate the top nine safety risks. SCE's testimony also includes responses to the feedback provided by the Commission's Safety Policy Division (SPD) and intervening parties addressing SCE's 2022 RAMP Report, as well as additional information required by SCE's 2021 GRC decision, in accordance with D.14-12-025 and D.21-08-036.[116]

In its assessment of SCE's 2022 RAMP Report, SPD notes that each successive iteration of RAMP applications has generally shown improvements in the depth, rigor, and advances in the utilities' risk management approaches.[117] In this GRC, SCE leverages the prior approach used in its 2021 TY GRC while meeting applicable updated RAMP requirements. SCE's direct testimony clearly indicates whether the work performed within a GRC activity relates to a control, mitigation, or foundational activity as described in SCE's 2022 RAMP Report, while SCE's "RAMP Integration" section presents a comparison and reconciliation between what SCE estimated in its 2022 RAMP Report and what SCE forecast in this GRC. Further, as applicable, SCE's testimony addresses SPD and/or party feedback on SCE's 2022 RAMP Report, and identifies any updates or changes to SCE's risk modeling assumptions and values.

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[114] In the 2022 RAMP Report, some risks have been combined or separated as standalone risks.

[115] Ex. SCE-01, Vol. 2 at 7-20.

[116] Ex. SCE-01, Vol. 2 at 10-17 and 26-27; D.14-12-025 at 40; D.21-08-036 at 37.

[117] Ex. SCE-01, Vol. 2 at 10.

6.1. Quantitative Risk Modeling

In D.18-12-014, the Commission approved, with modifications, an uncontested settlement agreement between the IOUs and intervenors setting forth the minimum required elements and specific steps the IOUs must follow to perform a quantitative assessment of the risk and mitigation choices in the IOUs' RAMP and GRC filings, otherwise known as the Risk-based Decision-making Framework (RDF).[118] To assess the current state of risk on the system, the RDF requires a utility to calculate baseline risk scores for portions of its system with similar risk profiles, referred to as tranches. The RDF defines risk as the likelihood of a risk event times the consequence of a risk event, and provides a common framework for translating different safety, financial, and reliability consequences into a unitless risk score that can be used to compare different risks and their mitigations.[119] The final step of the RDF is the calculation of risk spend efficiency (RSE) values for each risk mitigation program, both in the aggregate (*i.e.*, for the entire proposed program) and broken down by tranche.[120]

TURN asserts the quantitative risk analysis required by the RDF is a "vital tool to ensure finite ratepayer funding is used reasonably and cost-effectively," and that SCE attempts to downplay the usefulness of the results of the required quantitative risk analysis in certain wildfire grid hardening and vegetation

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[118] The RDF was defined in Appendix A as part of the D.18-12-014 Settlement Agreement.

[119] D.18-12-014 at 43-49 and Appendix A; D.22-12-027 at 13-17; TURN OB at 58, 60-62.

[120] RSE is calculated by dividing the present value of the risk reduction of a mitigation by the present value of the cost to implement the mitigation. In D.22-12-027, the Commission modified the risk decision-making approach adopted in D.18-12-014 to a Cost-Benefit Approach, whereby combined risk attributes are represented as dollars rather than as unitless risk scores. SCE is not required to transition to the Cost-Benefit Approach until its next RAMP submission, and SCE presented RSE calculations with its direct testimony as part of this GRC showing. (D.22-12-027 at 17-30; Ex. SCE-04, Vol. 5, Pt. 1A WP at 25-52).

management requests in this GRC.[121] TURN goes on to state the Commission developed the quantitative risk analysis as a useful tool to prioritize risk reduction spending. Lastly, TURN's testimony supplements the information presented by SCE in this proceeding in two ways. First, TURN's testimony calculates alternative RSEs using different discount rate assumptions than those that underpin SCE's RSE calculation.[122] TURN asserts the three percent discount rate SCE selected to discount risk reduction is inadequately supported, and that risk reduction and costs in the RSE calculation must be uniformly discounted to avoid bias.[123] Second, TURN's testimony converts SCE's RSE values to Benefit/Cost Ratios.[124]

In response, SCE states RSEs are one factor in the decision-making process, and that SCE's position is consistent with Commission policy. Concerning the discount rates used to calculate RSE values, SCE asserts TURN's position is contravened by guidance from the policy paper issued by SPD, while the issue of discount rates continues to be actively discussed in the Commission's risk decision-making rulemaking (R.20-07-013).[125]

Consistent with prior precedent, this decision considers RSEs and associated proposed mitigations on a case-by-case basis. The Commission has held that RSEs "provide a useful point of comparison regarding the

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[121] TURN OB at 59.

[122] SCE uses a three percent discount rate for benefits (risk reduction, the numerator of the RSE calculation), and a weighted average cost of capital (WACC) of 7.44 percent for costs (dollars, the denominator of the RSE calculation). In contrast, TURN uses a uniform WACC discount rate for both the numerator and denominator of the RSE calculation. (Ex. TURN-04 at 11-12).

[123] Ex. TURN-04 at 6-11.

[124] Ex. TURN-04 at 2-18; TURN OB at 58-67.

[125] Ex. SCE-12 at 3-4; SCE OB at 25.

cost-effectiveness of proposed mitigations belonging to the same risk tranche,"[126] and are "critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds."[127] Further, one of the goals of the RDF is to "use risk reduction per dollar spent to prioritize projects."[128] As noted by TURN, the current RDF also reflects over a decade of time and effort by the Commission and parties to implement a uniform approach for quantifying risk reduction and the cost-effectiveness of utility mitigation proposals.

However, the Commission has also held that the utility is "not bound to select its mitigation strategy based solely on RSE rankings," and may be influenced by other factors including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations.[129] As the applicant, SCE bears the burden of affirmatively establishing the reasonableness of all aspects of its Application, including any deviations from calculated RSE values. Within its proposed risk mitigation activities, SCE must also clearly explain its rationale for selecting the type, scale, and prioritization of risk mitigations, including how RSE calculations were considered.[130]

Concerning TURN's recommendation to apply a uniform discount rate in the RSE calculation, this issue has already been addressed in R.20-07-013, the

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[126] D.21-08-036 Finding of Fact 32.

[127] D.21-08-036 at 38 (citing to Resolution WSD-002 and Resolution WSD-004); D.23-11-069 at 44.

[128] D.18-12-014 at 12 and 14.

[129] D.18-12-014, Attachment A, Row 26 at A-14.

[130] D.21-08-016 at 38.

Commission's Risk Decision-Making Framework, and does not warrant further discussion here.[131]

6.2. Climate Change Policy

Pursuant to D.20-08-046, each IOU is required to submit a Climate Adaptation and Vulnerability Assessment (CAVA) one year before filing its respective GRC application. D.20-08-046 also requires the IOUs to "include in their General Rate Case filings the main takeaways from the vulnerability assessments as a separate section or chapter that contains, at a minimum: (1) a list of vulnerabilities; (2) proposals addressing those vulnerabilities (with options); and (3) long-term goals for adapting to climate risks."[132]

Per Commission guidance, SCE submitted its CAVA through an advice letter filing on May 13, 2022.[133] As part of the CAVA filing, SCE studied the risks that its Assets, Operations, and Services would face due to changing temperature, sea level rise, precipitation, wildfire, and cascading events, and identified and proposed potential adaptation options to address these vulnerabilities and risks. Per CAVA requirements, SCE gave particular focus in its assessment on the impact that loss of electricity service due to climate change could have on its customers, especially those in disadvantaged vulnerable

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[131] *See* D.24-05-064 at 102-105.

[132] D.20-08-046, Ordering Paragraphs 11-12. In D.24-08-005, the Commission adopted updates to the CAVA requirements and to corresponding investment proposals, including a requirement that investment proposals must demonstrate incrementality. The updated requirements do not apply to SCE's current GRC application. (D.24-08-005, Conclusion of Law 15 and Ordering Paragraph 1).

[133] *See* SCE Advice Letter 4793-E/4793-E-A.

communities (DVC).[134] SCE's analysis was conducted over multiple time horizons, ranging from 2030 to 2070. The risks identified in the 2030 timeframe served as the foundation for the adaptation options proposed in this GRC; however, SCE also identified select adaptation measures for longer-term timeframes (*i.e.*, 2050 and 2070).[135] SCE's advice letter filing was deemed effective as of May 13, 2022.[136]

SCE states the need for adaptation measures is expected to increase over the next 20 to 30 years, as projected climate impacts worsen, and that longer-term and potentially more significant adaptation investments require more mature climate science that can generate more granular magnitude and frequency projections. SCE expects climate adaptation needs to continue to grow over time and, as a result, funding requests to be more expansive in future GRCs.[137] Lastly, to support a more orderly CAVA/RAMP integration process, SCE recommends the Commission consider placing some separation between the CAVA and RAMP filing dates.[138] SCE's Climate Change Policy testimony was not directly challenged by any party in this proceeding.

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[134] For the purpose of the CAVA reports, DVCs consist of "communities in the 25% highest scoring census tracts according to the most recent version of the California Communities Environmental Health Screening Tool (CalEnviroScreen), as well as all California tribal lands, census tracts with median household incomes less than 60% of state median income, and census tracts that score in the highest 5% of Pollution Burden within CalEnviroScreen, but do not receive an overall CalEnviroScreen score due to unreliable public health and socioeconomic data." (D.20-08-046, Conclusion of Law 2).

[135] Ex. SCE-01, Vol. 2 at 32-40.

[136] Ex. SCE-01, Vol. 2, footnote 57 at 32. A list of CAVA-identified risks and associated adaptation options, with specific information mapping inclusion in SCE's GRC Application, is shown in Ex. SCE-01, Vol. 2, Table V-3 and Table V-4 at 39-40.

[137] SCE OB at 26.

[138] Ex. SCE-01, Vol. 2 at 42.

SCE's CAVA filing was the first of its kind amongst the California electric IOUs, and constitutes a more thorough approach to how the utilities plan and prepare for increased operational risks due to changing climate conditions and events. In compliance with D.20-08-046, the vulnerability assessment SCE presents in this GRC identifies the challenges SCE will face due to climate change, and includes a suite of potential mitigation options for consideration. Further, we find SCE's guiding principles for the adaptation options considered in this GRC, including the direction to focus on near-term risks, to be reasonable. Lastly, SCE's recommendation concerning the timing of the CAVA report was addressed in D.24-08-005, which modified the due date for the CAVA report to one year before an IOU's RAMP submission, starting with PG&E's next CAVA in 2027.[139]

6.3. Environmental and Social Justice Goals

In February 2019, the Commission adopted the Environmental and Social Justice (ESJ) Action Plan as a commitment to furthering the principles of environmental and social justice,[140] and to provide a comprehensive strategy and framework for addressing ESJ issues throughout the Commission and in individual Commission proceedings.[141] The ESJ Action Plan includes nine

[139] D.24-08-005 at 2.

[140] ESJ communities are defined as "predominantly communities of color or low-income communities that are underrepresented in the policy setting or decision-making process, subject to a disproportionate impact from one or more environmental hazards, and are likely to experience disparate implementation of environmental regulations and socioeconomic investments in their communities." (Commission's ESJ Action Plan 1.0, dated February 21, 2019, at 6).

[141] The Commission's ESJ Action Plans are available at: https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan (last accessed October 1, 2024).

guiding principles designed to inform the Commission's strategies to advance ESJ issues.[142] On April 7, 2022, the Commission adopted the ESJ Action Plan 2.0 to incorporate learnings from ongoing implementation activities and to deepen and enhance the goals of the ESJ Action Plan.[143]

In its direct testimony, SCE states it complies with and supports the nine guiding principles found in the ESJ Action Plan and includes, among other showings, a description of: (1) the GRC activities and applicable business units that support ESJ goals; (2) SCE's clean energy resource investments targeted towards ESJ communities; (3) the equity considerations embedded in SCE's climate risk assessments and proposed climate resiliency mitigation projects; (4) SCE's engagement and outreach work with CBOs, tribes, ESJ community leaders, and other representatives from key customer segments; (5) SCE's initiatives and programs focused on ESJ communities; (6) the activities SCE conducts to improve communication skills and trust through trainings and staff development activities; and (7) SCE's efforts to monitor and evaluate the success of ESJ programs.[144]

TURN, SBUA, and the Joint Ratepayers argue that increasing electric rates to enable the grid investments needed to foster electrification is counter to the ESJ Action Plan and will disproportionately harm lower income customers.[145] Cal Advocates asserts the Commission "should consider SCE's requests in an equitable way to all communities, including Disadvantaged Communities, tribal

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[142] Commission's ESJ Action Plan 1.0, dated February 21, 2019, at 6-8.

[143] Commission's ESJ Action Plan 2.0, dated April 7, 2022, at 2-4.

[144] Ex. SCE-01, Vol. 2 at 43-55.

[145] Ex. TURN-03 at 9-10; Ex. SBUA-01 at 28; Ex. Joint Ratepayers-01 at 21.

lands, and low-income households and census tracts, pursuant to the Environmental & Social Justice (ESJ) Action Plan."[146] TURN asserts SCE's request for a 22.6 percent increase to its revenue requirement, on top of what was already requested in Track 4 of SCE's 2021 GRC, significantly harms low- and middle-income customers, that utility bill unaffordability increases the likelihood of homelessness, and that the transition to transportation electrification needs to be done equitably and not at the expense of the most vulnerable ratepayers.[147]

Intervenor comments largely focus on the nexus between affordability and equity. These and other issues are discussed at length in Section 5 (Affordability and Equity), while TURN's recommendation concerning the equitable transition to transportation electrification is considered in Section 12 (Load Growth, Transmission Projects, and Engineering). In all other aspects, SCE's ESJ testimony was not directly challenged by any party, while SCE's testimony identifies several clean energy programs and initiatives that focus specifically on ESJ communities, including the Energy Savings Assistance Program, Self-Generation Incentive Program, San Joaquin Valley Pilot, and California Clean Fuel Reward program, among others.[148] We find these remaining sections of SCE's Application and testimony to be consistent with the goals, objectives, and action items included in the Commission's ESJ Action Plan.

[146] Cal Advocates OB at 8.

[147] TURN OB at 27-28 and 47-54.

[148] Ex. SCE-07, Vol. 4 at 20-21; Ex. SCE-12 at 10-12.

7. Distribution Grid

7.1. Grid Policy

SCE presents an array of distribution grid policy and infrastructure issues before the Commission. Generally, these issues fall within the following categories: (1) obsolete equipment; (2) acceleration of customer electrification; (3) increased need for reliable electricity; (4) increased severity of climate risks to distribution and grid assets; and (5) increased, new types of load and generation.

First, SCE states that the average age of SCE's infrastructure has increased over the last several years as replacement rates have been lower than previous times.[149] SCE states that 25 percent of its underground cable is roughly 40 years old and SCE expects this population of aging equipment to grow by 38 percent by 2028. SCE also states that it has seen primary underground cable failures increase by 100 percent, partly due to the age of the asset.[150]

SCE testimony shows that some of its equipment is obsolete. SCE testifies that having obsolete equipment makes it harder to maintain given the lack of both vendor support and manufactured spare parts. Over 15 percent of SCE's distribution circuits and substations are 4 kilovolt (kV) systems that were built 60 to 80 years ago. SCE testifies that these assets no longer meet modern standards, pose significant challenges due to capacity constraints, have incompatible design with surrounding infrastructure, and present space restrictions that pose safety and operational challenges. Thus, the combination of age, obsolescence, and

[149] Ex. SCE-02, Vol. 1, Pt. 1 at 3.

[150] Ex. SCE-02, Vol. 1, Pt. 2 at Chapter II, Section C.1.(a)(2).

limiting designs that do not meet current standards leads to a higher probability of safety incidents and outages, as well as longer outages when they do occur.[151]

Second, in addition to the above, SCE states that customer electrification is accelerating. SCE projects that in certain areas, on a localized basis, loads could as much as double between 2021 and 2031. Across energy and capacity demand forecasts, SCE asserts there is consensus that customer electrification will drive significant increases in the rate of load growth as more consumers and businesses adopt electricity for transportation, heating, and other needs.[152]

SCE also states that federal and state programs and incentives are expected to further boost electrification. SCE testifies that 19 percent of new light-duty vehicle sales in SCE's service area were zero emissions vehicles or plug-in hybrid vehicles in 2022.[153] SCE testifies that the increasing rate of customer requests for electricity is already beginning to create challenges in meeting energization requests. SCE states that in many cases, the grid lacks sufficient local distribution capacity to meet customer load demands within the customers' requested timelines. SCE testifies that this is particularly acute for medium- and heavy-duty transportation electrification loads which create concentrated power requirements that will need significant infrastructure to serve. SCE estimates that this infrastructure will require charging depot needs anywhere from 3.5 megawatt (MW) to 23.5 MW per site.[154]

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[151] Ex. SCE-02, Vol. 1, Pt. 1 at 3.

[152] Ex. SCE-02, Vol. 1, Pt. 1 at 4.

[153] Ex. SCE-02, Vol. 1, Pt. 1 at 5.

[154] Ex. SCE-02, Vol. 1, Pt. 1 at 6.

Third, while customer needs for reliable electricity are increasing, SCE's reliability has fluctuated over the last 10 years. SCE states that its System Average Interruption Duration Index (SAIDI) has been worsening since 2018 and eroded to over 100 minutes in 2021. SCE testifies that it is imperative for it to replace and update its aging infrastructure to reduce both the number and length of outages, and to minimize the number of customers that are impacted when outages occur.[155]

Fourth, climate risks to grid assets are increasing in severity. SCE testifies that by 2050, Southern California could expect to see the following climate impacts relative to pre-industrial levels: (1) average temperature is projected to rise three to five degrees; (2) temperatures as hot or hotter than the historical 99th percentile temperature are projected to occur seven times more frequently; (3) 23 percent more acreage is projected to burn during summer fuel-driven wildfires, and wildfire seasons are expected to be longer; (4) precipitation levels are expected to result in up to a 40 percent decline in snowpack alongside more intense droughts, with less but more intense precipitation throughout California; and (5) sea level is projected to increase by 2.6 feet relative to levels in 2000.[156]

Against all of this, SCE states that newer types of loads and generation are increasing and adding complexity. For example, the increasing deployment of inverter-based resources, across generation and load, heightens complexity in both planning and operations. SCE states that the loads associated with customer electrification (*i.e.*, electric vehicle charging) have new characteristics such as sharp ramp up or ramp down and geographic mobility. Electric vehicle

[155] Ex. SCE-02, Vol. 1, Pt. 1 at 9.

[156] Ex. SCE-02, Vol. 1, Pt. 1 at 12.

loads are also increasingly dynamic because customers can charge at different locations.[157]

On the generation side, SCE testifies that the advent of distributed inverter-based resources, with expected growth between 2019 and 2030 of 260 percent for behind-the-meter solar photovoltaic, and 770 percent for behind-the-meter energy storage, presents grid stability challenges in the form of bi-directional power flows and voltage fluctuations. SCE states that at the same time, in order to achieve carbon neutrality, bulk generation resources will also shift to primarily inverter-based resources.[158]

7.2. DIR Program Overview

As discussed above, SCE's infrastructure is aging. SCE states that every piece of infrastructure wears out through operational wear and tear and external factors such as weather.[159] SCE's DIR Program addresses activities SCE will undertake to proactively plan for infrastructure replacements and upgrades for its distribution infrastructure.[160] As a result of this aging, SCE forecasts the following capital expenditures to perform reasonable replacement of SCE's distribution assets and equipment to continue to provide reliable service to its customers:[161]

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[157] Ex. SCE-02, Vol. 1, Pt. 1 at 12.

[158] Ex. SCE-02, Vol. 1, Pt. 1 at 13.

[159] Ex. SCE-13, Vol. 1 at 1.

[160] Distribution Infrastructure refers to major equipment that makes up the 33 kV and below distribution system such as poles, transformers, switches, capacitors, automatic reclosers, cable, and conductors. *See* Ex. SCE-13, Vol. 1 at 1.

[161] Ex. SCE-02, Vol. 1, Pt. 2 at 1. *See also* Ex. SCE-11 at B-1.

- $3.788 billion of capital expenditures for years 2023 (recorded) and 2024-2028 (forecast) to address the DIR Program.[162]
- Capital expenditure forecast for DIR is approximately 15 percent of SCE's total forecast for distribution grid capital expenditures for 2023-2028.[163]

The DIR Program encompasses 13 programs SCE intends to leverage to inspect and maintain its electric distribution system.[164] This equipment typically operates for many years but eventually wears out and must be replaced as part of maintaining an adequate distribution system.[165] SCE relies on proactive infrastructure replacements and upgrades for certain asset classes to reduce the risks of in-service equipment failures.[166]

The primary drivers for SCE's DIR Programs are safety, service reliability, capacity needs, and aging infrastructure.[167] The drivers for SCE's Worst Performing Circuit (WPC) Program and parts of its Underground Cable Replacement Program (UCR) are the annual reliability reporting requirements established by D.16-01-008, and the requirement to file plans, within this reporting, to improve the reliability performance of repeat WPCs within SCE's service area.[168]

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[162] Ex. SCE-02, Vol. 1, Pt. 2 at 1. Updated with 2023 recorded costs from Ex. SCE-11 at B-1.

[163] Ex. SCE-02, Vol. 1, Pt.2 at 3.

[164] Ex. SCE-02, Vol. 1, Pt. 2 at 1.

[165] Ex. SCE-02, Vol. 1, Pt. 2 at 4.

[166] Ex. SCE-02, Vol. 1, Pt. 2 at 5.

[167] Ex. SCE-02, Vol. 1, Pt. 2 at 8-12.

[168] Ex. SCE-02, Vol. 1, Pt. 2 at 23.

In its 2021 GRC and its annual Risk Spending Accountability Reports, SCE stated the scope of its DIR efforts was temporarily reduced beginning in 2019 to address wildfire threats.[169] SCE states its increased forecasts for DIR are essentially a return to its 2018 recorded costs levels for DIR.[170] Thus, SCE's DIR Program request amounts to $1.2 billion in expenditures for years 2023-2025, of which SCE requests $801 million for 2025.

SCE states that this capital expenditure request is a return to 2018 spending levels and asks that the Commission fund the equivalent level of DIR spending that SCE recorded in 2018.[171] SCE asks the Commission to consider the historical context of previous levels of recorded capital expenditures. SCE testifies that the historical levels of spending had to be reduced beginning in 2018 to allow SCE to reallocate resources to address emergent statewide wildfire threats, primarily for its Wildfire Covered Conductor Program (WCCP), which is the largest grid hardening activity in SCE's Wildfire Mitigation Plans (WMP).[172] Consequently, SCE states that given today's different climate policy landscape and grid needs compared to those in SCE's previous two GRCs, SCE undertook an extensive analysis to provide the Commission with a historical comparison of recorded costs in relation to this current request. SCE testifies that it provides an equivalent comparison, using 2022 constant dollars, for a like-for-like comparison of recorded and forecast DIR activities.[173]

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[169] Ex. SCE-02 Vol. 1, Pt. 2 at 12-13.

[170] Ex. SCE-02, Vol. 1 Pt. 2 at 13.

[171] Ex. SCE-13, Vol. 1 at 5.

[172] Ex. SCE-13, Vol. 1 at 4.

[173] Ex. SCE-13, Vol. 1 at 5.

In SCE's testimony, SCE states that its maintenance programs alone are not sufficient to provide adequate service to its customers.[174] SCE states that these efforts serve to reduce the risks of in-service equipment failures and the attendant safety and reliability consequences of such failures. The planned and proactive infrastructure replacement efforts also help ensure that grid assets are fully capable of meeting the current and future needs of customers and promoting the electrification goals and emission targets of the state.[175] Specifically, SCE identifies the following categories that drive its DIR Programs: (1) public and employee safety; (2) reliability; and (3) capacity challenges.[176] Next, we summarize each of the DIR Programs, below.

7.2.1. Underground Infrastructure

SCE's underground distribution system is comprised of cable and cable components, typically installed within systems of underground ducts between structures such as vaults or manholes. The underground system also contains a variety of electrical components such as underground switches and underground transformers, which are typically installed within underground structures.[177]

SCE asserts that as underground electrical components and structures inevitably degrade over time from age, normal operational wear and tear, and environmental factors, the probability of in-service failures naturally increases.[178] Underground systems are inherently more difficult to inspect than overhead systems due to limited visibility and accessibility and need for additional

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[174] Ex. SCE-02, Vol. 1, Pt. 1 at 4.

[175] Ex. SCE-02, Vol. 1, Pt. 1 at 5.

[176] Ex. SCE-02, Vol. 1, Pt. 1 at 7.

[177] Ex. SCE-02, Vol. 1, Pt. 2 at 27.

[178] Ex. SCE-02, Vol. 1, Pt. 2 at 27.

operational steps such as pumping out water, traffic control, and ventilation. Similarly, SCE states that fault location and switching to isolate segments and minimize customer impacts are more complex and time-consuming endeavors for underground systems. SCE testifies that underground equipment failure can have substantial safety and reliability impacts and therefore, proactively replacing aged and degraded equipment and structures is critical.[179] SCE proposes the programs below to address these needs.

7.2.1.1. Underground Cable Replacement Program

SCE presents its Underground Cable Replacement (UCR) Program as a program that targets proactive replacement of mainline underground cables and cable components. Previously, in the 2021 GRC, the UCR Program was called the Worst Circuit Rehabilitation Program (WCRP), which also included the Worst-Performing Circuit Program (WCP). Here, in the 2025 GRC, the UCR and the WCP are separated into two programs.[180]

SCE states over 45 percent of its primary distribution system, or approximately 66,600 conductor miles, is underground and there are approximately 1,300 underground cable failures annually.[181] When an underground cable or cable component fails, it results in a fault which can: (1) release large amounts of energy; (2) generate combustible gases; and (3) in extreme circumstances, produce an explosion which dislodges vaults or manhole covers. In its testimony, SCE discusses the safety risks associated with

[179] Ex. SCE-02, Vol. 1, Pt. 2 at 28

[180] Ex. SCE-02, Vol. 1, Pt. 2 at 28.

[181] Ex. SCE-02, Vol. 1, Pt. 2 at 30-34.

underground cable and cable component failures,[182] the reliability risks associated with underground cable and cable component failures,[183] how aging cable and prolonged exposure to the environment contribute to cable failure,[184] and how overloading from extreme load demands from extreme weather events leads to cable failure.[185]

Given this context, SCE is proposing to proactively replace 1,600 conductor miles of four mainline underground cable from 2025-2028 to adequately mitigate the safety and reliability risks associated with underground cable and component failure. SCE states that the 2025-2028 proposed scope is less than 10 percent of the cable 38 years or older as of the time of filing.[186] SCE proposes to proactively replace 400 of the higher-risk miles per year.[187] Replacing 1,600 miles over this GRC period is expected to reduce approximately 80 percent of safety and reliability risk associated with mainline underground cable for cable at least 41 years old. SCE testifies that it used predictive modeling to prioritize the scope of the UCR program.[188] SCE developed a forecast method to develop UCR program needs.

For the 2023-2025 period, SCE's UCR program has a forecast cost of $118.471 million.[189] The forecast method for UCR is the average unit cost for an

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[182] Ex. SCE-02, Vol. 1, Pt. 2 at 30.

[183] Ex. SCE-02, Vol. 1, Pt. 2 at 32,

[184] Ex. SCE-02, Vol. 1, Pt. 2 at 33-36.

[185] Ex. SCE-02, Vol. 1, Pt. 2 at 36-37.

[186] Ex. SCE-02, Vol. 1, Pt. 2 at 37.

[187] Ex. SCE-02, Vol. 1, Pt. 2 at 38.

[188] Ex. SCE-02, Vol. 1, Pt. 2 at 38.

[189] Ex. SCE-13, Vol. 1 at 7.

underground cable conductor mile multiplied by the anticipated number of conductor miles mitigated for each year in the 2023-2028 period.[190] The average unit cost was estimated using the most recent completed work orders in 2021 and then escalated to 2022 dollars. The 2021 closed work orders reflect the current cost environment as they provide direct insight into the most recent and true costs incurred by SCE to execute this work.[191] Cal Advocates and TURN dispute the UCR program's forecast and offer alternative forecasts which we discuss below.

7.2.1.2. Cable Life Extension Program

Approximately 12,000 conductor miles, or one-fifth of SCE's cable population, is cable-in-conduit (CIC).[192] The Cable Life Extension (CLE) Program seeks to prolong the life of radial (as opposed to mainline) cable segments between 25 and 50 years of age by injecting a silicone-based fluid along the strands of the cable to fill voids in the CIC insulation.[193] Approximately 56 percent of the entire CIC population is between 25 and 50 years of age.[194] SCE testifies that this approach is preferred due to lower costs of extending cable life, compared to replacement, which allows the asset to remain in service and lessens the probability of failure.[195] SCE also testifies that the CLE Program was paused in 2020 to prevent a backlog of projects in the CIC Replacement Program, which

[190] Ex. SCE-02, Vol. 1, Pt. 2 at 39, Table II-6.

[191] Ex. SCE-02, Vol. 1, Pt. 2 at 39.

[192] Ex. SCE-02, Vol. 1, Pt. 2 at 42.

[193] Ex. SCE-02, Vol. 1, Pt. 2 at 42-43.

[194] Ex. SCE-02, Vol. 1, Pt. 2 at 49.

[195] Ex. SCE-02, Vol. 1, Pt. 2 at 42.

was driven by the need to reallocate resources to wildfire mitigation. In 2025, SCE forecasts returning to more historical levels of cable rejuvenation.[196]

Cables exhibiting less than 50 percent concentric neutral degradation are candidates for injection.[197] SCE states that the CLE is the most cost-effective alternative for remediation of CIC between the ages of 25 to 50 years of age. SCE states that when CIC is successfully rejuvenated, it is expected to extend cable life for approximately twenty years at approximately one-third of the cost of cable replacement.[198] SCE states the CLE Program forecast is reasonable because it addresses the aging cable population, will provide valuable life extension benefits to SCE's aging radial cable systems, and will allow SCE to return to historical replacement levels.[199]

SCE's 2023-2025 capital forecast for the CLE program is $15.879 million. [200] SCE states that the forecast method for the CLE Program is the average unit cost for rejuvenating one conductor mile of cable multiplied by the anticipated number of conductor miles to be rejuvenated for each year from 2023-2028. The average unit cost is a blended average determined using a 2017-2018 average cost per unit, along with an estimate from a vendor for testing per conductor mile, and then escalated to 2022 dollars.[201] The forecast for the CLE program is undisputed.

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[196] Ex. SCE-02, Vol. 1, Pt. 2 at 44.

[197] Ex. SCE-02, Vol. 1, Pt. 2 at 45.

[198] Ex. SCE-02, Vol. 1, Pt. 2 at 50.

[199] Ex. SCE-02, Vol. 1, Pt. 2 at 53.

[200] Ex. SCE-13, Vol. 1 at 7.

[201] Ex. SCE-02, Vol. 1, Pt. 2 at 52.

7.2.1.3. Cable-in-Conduit Program

SCE forecasts $76.414 million for the 2023-2025 CIC Replacement Program. The forecast method for the CIC Replacement Program is the average unit cost for replacing one conductor mile of cable multiplied by the anticipated number of conductor miles to be replaced for each year, 2023-2028.[202] SCE states that the average unit cost was estimated using the most recent completed work orders in 2021 and then escalated to 2022 dollars. SCE also states that the 2021 closed work orders reflect the current cost environment and provide direct insight into the most recent and true costs incurred by SCE to execute the CIC Replacement Program work.[203]

The forecast for the CIC Replacement Program is undisputed.

7.2.1.4. Underground Switch Replacement Program

SCE's Underground Switch Replacement Program replaces switches, approaching or exceeding the end of their service life, in underground structures to reduce risk to system reliability and public and employee safety.[204] Underground circuits contain both subsurface and pad-mounted switches. SCE states it prioritizes oil-filled switch replacements because many are no longer manufactured or supported which results in operational and maintenance challenges.[205] SCE states its system has experienced an average of 116 underground switch failures per year or approximately 5.6 percent of total annual observed Underground Equipment Failures. Failures of oil-filled and gas

[202] Ex. SCE-02, Vol. 1, Pt. 2 at 52.

[203] Ex. SCE-02, Vol. 1, Pt. 2 at 53.

[204] Ex. SCE-02, Vol. 1, Pt. 2 at 54.

[205] Ex. SCE-02, Vol. 1, Pt. 2 at 56.

switches can be violent and can damage adjacent electrical equipment (*i.e.*, cable, transformers, switches).[206] SCE states that corrosion is the main risk driver for gas and oil-filled switches.[207] The Underground Switch Replacement Program scope proposes to replace 900 of the higher risk mainline and radial switches over this GRC period to mitigate approximately 27 percent of the risk associated with underground switches.[208] Beginning in 2025, replacement of underground switches will utilize SF6-alternative technologies to comply with recent changes to Title 17, California Code of Regulations.[209]

For the 2023-2025 period, SCE forecasts $19.472 million for the Underground Switch Replacement Program. [210] SCE states the forecast method for the Underground Switch Replacement Program is the average unit cost for replacing an underground switch multiplied by the anticipated number of switches to be replaced for each year in the 2023-2028 forecast. SCE testifies that the average unit cost was estimated using the most recent completed work orders in 2021 and then escalating this amount to 2022 dollars. SCE also testifies that the 2021 completed work orders reflect the most true and immediate costs incurred by SCE.[211] The forecast for the Underground Switch Replacement Program is generally undisputed.

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[206] Ex. SCE-02, Vol. 1, Pt. 2 at 58.

[207] Ex. SCE-02, Vol. 1, Pt. 2 at 59.

[208] Ex. SCE-02, Vol. 1, Pt. 2 at 60.

[209] Ex. SCE-02, Vol. 1, Pt. 2 at 62.

[210] Ex. SCE-13, Vol. 1 at 7.

[211] Ex. SCE-02, Vol. 1, Pt. 2 at 61.

7.2.1.5. Underground Structure Replacement Program

The Underground Structure Replacement Program consists of an array of activities, including the following: (1) structure replacements to install new structures where significant deterioration is observed; (2) structure shoring to extend the life of deteriorating structures; and (3) the Cover Pressure Relief and Restraint (CPRR) program to reduce the consequences from vault explosions.[212] SCE has over 42,000 vaults and manholes throughout its service and nearly 15,000 of these are older than their estimated useful life of 40-50 years.[213] SCE testifies that age, environmental, and structural design are factors contributing to vault and manhole deterioration.[214] From 2021-2022, there have been 44 explosion events related to vaults and manholes.[215]

SCE states that activities in 2023 and 2024 will continue as previously scoped.[216] For 2025-2028, SCE plans to annually replace approximately 105 underground structures and annually shore approximately 45 underground structures. For 2025-2028, SCE aims to address 1,400 (350 per year) manhole/vaults by replacing their conventional, circular lid with a CPRR lid to mitigate 14 percent of projectile risk including the lid, structure pieces, and pavement near the vault or manhole entrance.[217] SCE testifies that the forecast for the underground structure replacements and shoring is reasonable because it

[212] Ex. SCE-02, Vol. 1, Pt. 2 at 68.

[213] Ex. SCE-02, Vol. 1, Pt. 2 at 65.

[214] Ex. SCE-02, Vol. 1, Pt. 2 at 65.

[215] Ex. SCE-02, Vol. 1, Pt. 2 at 76.

[216] Ex. SCE-02, Vol. 1, Pt. 2 at 77.

[217] Ex. SCE-02, Vol. 1, Pt. 2, at 77.

allows SCE to address the expected increase of underground replacements and shoring work due to aging and deteriorated conditions. SCE testifies that in D.21-08-036, the Commission directed SCE to replace and shore certain underground structures within this GRC cycle. SCE testifies that to address these requirements, SCE replaced 55 structures and shored or remediated 22 structures during 2021-2022.[218]

For the 2023-2025 period, SCE forecasts $181.059 million for the Underground Structure Replacement Program.[219] SCE states that the forecast method for the Underground Structure Replacement Program is the average unit cost for replacing or shoring an underground structure multiplied by the anticipated number of structures to be replaced or shored for each year in the 2023-2028 forecast. Different average unit costs were supplied for replacing an underground structure, shoring an underground structure, and replacing a conventional lid with a CPRR lid.[220] SCE states that all average unit costs were based on 2021 closed work orders and then escalating these amounts to 2022 dollars. Further, SCE states that when applicable, the average unit costs include a blended cost for all traditional replacements, modular replacements, and associated electrical equipment.[221] The forecast for the Underground Structure Replacement Program is undisputed.

7.2.2. Overhead Infrastructure

SCE's distribution system is predominantly configured with overhead apparatus. Since these assets play a critical role in maintaining safety and

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[218] Ex. SCE-02, Vol. 1, Pt. 2 at 80.

[219] Ex. SCE-13, Vol. 1 at 7.

[220] Ex. SCE-02, Vol. 1, Pt. 2 at 78, Table II-18.

[221] Ex. SCE-02, Vol. 1, Pt. 2 at 78.

reliability, SCE states it is imperative that it have the capability to replace aged and obsolete equipment in a prudently proactive and timely manner.[222] We discuss SCE's proposed activities for its overhead infrastructure, below.

7.2.2.1. Overhead Conductor Program

SCE testifies that overhead conductor failures can result in outages and wire-down events which may lead to road closures, property fires, wildfires, injuries, and at worst, fatalities.[223] The Overhead Conductor Program (OCP) was introduced in SCE's 2018 GRC to address public safety risks associated with energized downed overhead conductor.[224] SCE states its mitigation strategy involves replacing high-risk small-gauge wire with larger bare wires, lessening the probability of conductor failure associated with electrical faults and mechanical stressors.[225] OCP primarily includes proactive replacement informed by risk and engineering analysis, but also includes the Accelerated Overhead Conductor Program (AOCP) for replacing conductor after it has failed in service.[226] SCE's continued analysis of overhead conductor failures indicates large wires are also susceptible to failures and downed-wire events. SCE states that going forward, the scope for OCP will include all wire sizes and utilize covered conductor.[227]

For this GRC period, SCE's OCP is targeting higher-risk overhead conductors in non-high fire risk areas and in high fire risk areas that are not

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[222] Ex. SCE-02, Vol. 1, Pt. 2 at 80-81.

[223] Ex. SCE-02, Vol. 1, Pt. 2 at 82.

[224] Ex. SCE-02, Vol. 1, Pt. 2 at 81.

[225] Ex. SCE-02, Vol. 1, Pt. 2 at 83.

[226] Ex. SCE-02, Vol. 1, Pt. 2 at 84.

[227] Ex. SCE-02, Vol. 1, Pt. 2 at 83.

included in SCE's Wildfire Covered Conductor Program (WCCP).[228] SCE currently maintains and operates approximately 30,000 circuit miles of primary overhead conductor meeting these criteria.[229] SCE states that its OCP scope and prioritizing efforts are informed by machine learning predictive models that estimate the segment-specific probability and consequence of failure as well as resource availability, permitting constraints, and deployment efficiency.[230]

For 2025-2028, SCE plans to deploy covered conductor for 420 circuit miles annually, totaling 1,680 circuit miles. SCE estimates that this may mitigate approximately 30 percent of the risk associated with primary overhead conductor by the end of the GRC period.[231] SCE states that contact with energized equipment is the primary safety risk associated with overhead conductor. Secondarily, contact with energized equipment with wire-down events or contact with intact wire even when it is functioning properly present safety risks.[232]

From 2018 to 2022, SCE testifies that it experienced an average of 1,093 distribution primary conductor wire-down events annually, with a low of 1,029 in 2022 and a high of 1,153 in 2021.[233] During the 2018-2022 period, SCE states it recorded 19 serious injuries and fatalities with intact bare wire, with five incidents involving a fatality.[234] SCE also testifies that overhead conductor and

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[228] Ex. SCE-02, Vol. 1, Pt. 2 at 83.

[229] Ex. SCE-02, Vol. 1, Pt. 2 at 92.

[230] Ex. SCE-02, Vol. 1, Pt. 2 at 84.

[231] Ex. SCE-02, Vol. 1, Pt. 2 at 95.

[232] Ex. SCE-02, Vol. 1, Pt. 2 at 84.

[233] Ex. SCE-02, Vol. 1, Pt. 2 at 85.

[234] Ex. SCE-02, Vol. 1, Pt. 2 at 87.

component failures are a leading cause of unplanned outages for SCE's distribution system.[235] In the 2018-2022 period, approximately 48 percent of wire-down events were attributed to contact with foreign objects, approximately 30 percent were caused by equipment failures, and approximately 22 percent were due to an undetermined cause.[236]

SCE evaluated three scenarios for the OCP. These scenarios include: (1) replacing all high-risk spans with bare conductor; (2) replacing high-risk spans near the coast and locations with higher probability of contact with a foreign object with covered conductor and reconductoring the remaining high-risk spans with bare wire; and (3) replacing all high-risk spans with covered conductor.[237] Beginning in 2025, SCE states it will replace all high-risk spans with covered conductor because it has comparable mechanical strength to bare conductor of similar gauge, is less likely to be severed even when heavy branches fall on it or extraordinarily forceful contact occurs, and reduces the consequence of wire-down events.[238] SCE states that the materially greater benefits and risk mitigation are worth the incremental costs associated with covered conductor.[239]

In 2023, SCE recorded $70.796 million in costs for OCP. In 2024-2025, SCE forecasts $62.874 million and $332.799 million, respectively. SCE states that the forecast method for OCP is the average unit cost for replacing a circuit mile of

[235] Ex. SCE-02, Vol. 1, Pt. 2, at 87.

[236] Ex. SCE-02, Vol. 1, Pt. 2, at 89, Figure II-43.

[237] Ex. SCE-02, Vol. 1, Pt. 2 at 90.

[238] Ex. SCE-02, Vol. 1, Pt. 2 at 91-92.

[239] Ex. SCE-02, Vol. 1, Pt. 2 at 93.

overhead conductor multiplied by the anticipated number of circuit miles of overhead conductor to be replaced for each year in the 2023-2028 forecast.[240]

7.2.2.2. Overhead Switch Replacement Program

The Overhead Switch Replacement Program is a new program. The Overhead Switch Replacement Program targets the removal and replacement of 540 technologically obsolete overhead distribution gang-operated air-break (GOAB) switches and removes 1,000 Idle Installed Switches in 2025-2028.[241] SCE states that Idle Installed Switches occupy positions on circuits where they no longer serve a useful function and are identified as having no foreseeable future use.[242] SCE testifies that it has approximately 30,000 distribution GOAB switches, of which approximately 1,350 are obsolete and cannot be adequately maintained and operated due to technological obsolescence, unavailability of replacement parts, and lack of vendor support. Approximately 2,500 GOAB switches no longer support operational function at their present location and are considered idle.[243]

SCE states that the Overhead Switch Replacement Program is necessary to mitigate service reliability impacts and operational challenges.[244] SCE states that Idle switches present risk because their presence results in additional failure modes compared to wire and insulators.[245] SCE also states that the Overhead

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[240] Ex. SCE-02, Vol. 1, Pt. 2 at 96-97, Table II-23.

[241] Ex. SCE-02, Vol. 1, Pt. 2 at 99-106.

[242] Ex. SCE-02, Vol. 1, Pt. 2 at 102.

[243] Ex. SCE-02, Vol. 1, Pt. 2 at 100.

[244] Ex. SCE-02, Vol. 1, Pt. 2 at 100.

[245] Ex. SCE-02, Vol. 1, Pt. 2 at 105-106.

Switch Replacement Program provides the following benefits: (1) retires obsolete GOAB switches; (2) gains improved performance ratings and vendor support with present-day GOAB switches; and (3) better manages circuit positions with the current standard GOAB switch's automated ability.[246]

In 2023, SCE recorded $600,000 in costs associated with the Overhead Switch Replacement Program.[247] In 2025, SCE forecasts $6.815 million in costs associated with the Overhead Switch Replacement Program.[248] SCE states that the forecast method for the Overhead Switch Replacement Program is the average unit cost for replacing or removing an overhead switch multiplied by the anticipated number of switches to be replaced or removed for each year in the 2023-2028 forecast.[249] SCE also states that the average switch replacement unit cost uses average 2021 completed work orders and is then escalated to 2025 dollars.[250] The recorded and forecasted costs of the Overhead Switch Replacement Program are unopposed.

7.2.3. Overhead and Underground Infrastructure

7.2.3.1. Capacitor Bank Replacement Program

SCE's Capacitor Bank Replacement Program plans to replace or remove 1,236 failed and obsolete distribution capacitor banks in 2025-2028.[251] SCE testifies that nine percent of capacitor banks have been in service for 30 years or

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[246] Ex. SCE-02, Vol. 1, Pt. 2 at 107.

[247] Ex. SCE-02, Vol. 1, Pt. 2 at 2. *See also* updated with 2023 recorded costs from Ex. SCE-11 at B-1.

[248] Ex. SCE-02, Vol. 1, Pt. 2 at 2.

[249] Ex. SCE-02, Vol. 1, Pt. 2 at 108, Table II-26.

[250] Ex. SCE-02, Vol. 1, Pt. 2 at 108.

[251] Ex. SCE-02, Vol. 1, Pt. 2 at 108 and 114.

more.[252] SCE also testifies that capacitor banks are inspected every five years for proper operation, corrosion, leaking oil, and loose connections. SCE states that its risk analysis was inconclusive in identifying common drivers and did not allow SCE to target specific units based on catastrophic failure.[253]

For its GRC request, SCE states the Capacitor Bank Replacement Program targets incoming notifications on replacements and removals for capacitor banks and existing notifications from SCE's backlog.[254] Factors that contribute to capacitor bank failures include excessive number of switch operations, high ambient temperature, and corrosion.[255]

In 2023, SCE recorded $2.546 million in costs associated with the Capacitor Bank Replacement Program.[256] For 2024-2025, SCE forecasts $4.327 million and $16.827 million, respectively.[257] Thus, the program total is $23.700 million. SCE states that its forecast method for the Capacitor Bank Replacement Program is calculated by the average unit cost for replacing or removing a capacitor bank multiplied by the anticipated number of capacitor banks to be replaced or removed for each year in the 2023-2028 forecast.[258]

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[252] Ex. SCE-02, Vol. 1, Pt. 2 at 110.

[253] Ex. SCE-02, Vol. 1, Pt. 2 at 111.

[254] Ex. SCE-02, Vol. 1, Pt. 2 at 111-112.

[255] Ex. SCE-02, Vol. 1, Pt. 2 at 112.

[256] Ex. SCE-11 at B.

[257] Ex. SCE-02, Vol. 1, Pt. 2 at 116.

[258] Ex. SCE-02, Vol. 1, Pt. 2 at 116, Table II-28. Different average unit costs are supplied for overhead capacitor banks, padmount capacitor banks, and capacitor bank removal. The average unit cost for replacing an overhead capacitor bank is based on the most recent completed work orders in 2021, then escalated to 2022 dollars, which reflects the most true and immediate costs incurred by SCE.

The Capacitor Bank Replacement Program's recorded and forecasted costs are generally unopposed. Cal Advocates states it does not oppose SCE's forecast but recommends the following: (1) $4.238 million in 2023; (2) $4.355 million in 2024; and (3) $16.946 million in 2025.[259] Cal Advocates' forecasts are higher than SCE's original forecasts by $0.028 million for 2023, $0.028 million higher for 2024, and $0.119 million higher for 2025.[260]

7.2.3.2. Automatic Reclosers Replacement Program

The Automatic Reclosers Replacement Program targets the replacement of 17 oil-filled Distribution Automatic Reclosers and 15 oil-filled Vacuum Fault Interrupters (VFIs).[261] The 2025-2028 forecast reflects a shifting program from predominately Automatic Reclosers to include more VFI replacements.[262]

SCE states that many of the oldest Automatic Reclosers and VFIs are no longer manufactured, cannot be repaired, or are of obsolete design and may not operate properly to isolate system faults. SCE also states that bringing the equipment up to present standards will decrease the risk of in-service failures and downstream ignitions or outage risks.[263] SCE testifies that the main risk driver associated with oil-filled Automatic Reclosers and VFI switches is corrosion resulting in failures and subsequent replacements.[264] Beginning in

[259] Ex. CA-03 at 29-30.

[260] Ex. CA-03 at 29-30; *see also* Cal Advocates OB at 42.

[261] Ex. SCE-02, Vol. 1, Pt. 2 at 117 and 120.

[262] Ex. SCE-02, Vol. 1, Pt. 2 at 118.

[263] Ex. SCE-02, Vol. 1, Pt. 2 at 119.

[264] Ex. SCE-02, Vol. 1, Pt. 2 at 120.

2025, replacement VFI units will utilize SF6-alternative technologies to comply with recent changes to Title 17, California Code of Regulations.[265]

In 2023, SCE recorded $1.219 million in costs associated with the Automatic Reclosers Replacement Program. For 2025, SCE forecasts $1.454 million in associated costs.[266] Thus, total program costs amount to $2.673 million. SCE states that the forecast method for the Automatic Reclosers Replacement Program is the average unit cost for replacing Automatic Reclosers or VFI multiplied by the anticipated number of Automatic Reclosers and VFI to be replaced or removed for each forecasted year.[267] The Automatic Reclosers Replacement Program's recorded and forecasted costs are unopposed.

7.2.3.3. 4-kV Remediation Program

The 4-kV Remediation Program addresses aged and obsolete distribution and substation equipment that are in poor health or which have outdated system design limits, system load capacity, and/or impede operational flexibility. For this GRC period, SCE states that the 4-kV Remediation Program will begin integrating load growth-driven circuit cutovers which were presented separately in prior GRCs.[268] SCE states its current standards for distribution circuit primary voltage are 12-kV and 16-kV. SCE states it initiated its 4-kV Remediation Program more than a decade ago, but more than 150 4-kV substations and 700 4-kV circuits are still in service and require remediation.[269]

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[265] Ex. SCE-02, Vol. 1, Pt. 2 at 122.

[266] Ex. SCE-02, Vol. 1, Pt. 2 at 2. *See also* Ex. SCE-11, at B-1.

[267] Ex. SCE-02, Vol. 1, Pt. 2 at 121, Table II-30.

[268] Ex. SCE-02, Vol. 1, Pt. 2 at 129.

[269] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

The capacity limitations of 4-kV systems result in an inability to meet increasing customer load demand and a lack of operational flexibility. SCE states this restricts infrastructure upgrades and maintenance activities. Remediations can range from partial cutover of a circuit to substation rebuilds.[270] Approximately 75 percent of SCE's 4-kV substations serve highly populated urban areas, and SCE projects approximately 20 4-kV substations and 75 4-kV circuits will exceed designed load capacity between 2023 and 2031.[271] SCE states its risk models indicate 4-kV distribution assets have a 43 percent higher risk of failure compared to circuits at higher distribution voltages.[272] SCE also states that its 4-kV circuits are not conducive to transferring load to and from adjacent circuits.[273] The ages of 4-kV assets are high compared to the rest of the SCE system.[274] SCE testifies that 51 percent of 4-kV substation transformers and 41 percent of 4-kV circuit breakers require near-term replacement based on a health condition of poor or very poor.[275] SCE also testifies that it will take decades to remediate all 4-kV substations and circuits. Therefore, to prioritize the individual 4-kV systems, SCE uses a ranking system based on the critical attributes of individual 4-kV systems. This generates a numerical score which is coupled with engineering and site-specific issues. Taken together, this drives the prioritization of the project's scope. From 2023-2028, SCE proposes to address 38

[270] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

[271] Ex. SCE-02, Vol. 1, Pt. 2 at 132.

[272] Ex. SCE-02, Vol. 1, Pt. 2 at 132.

[273] Ex. SCE-02, Vol. 1, Pt. 2 at 133.

[274] Ex. SCE-02, Vol. 1, Pt. 2 at 135.

[275] Ex. SCE-02, Vol. 1, Pt. 2 at 136-137, Figures II-64 and II-65.

4-kV systems requiring remediation and to execute standalone (partial or full) cutovers on 4-kV circuits with near-term and time-sensitive capacity needs.[276]

In 2023, SCE recorded $90.448 million in costs associated with the 4-kV Remediation Program.[277] For 2024-2025, SCE forecasts $49.668 million and $127.378 million, respectively. Thus, the total cost of the 4-kV Remediation Program is $267.494 million.[278]

The annual forecasts for the 4-kV Remediation Program are the summation of the estimated costs for the individual remediation projects scoped for 2023-2028.[279] For projects that include distribution circuit and substation remediation, costs for the first year of a project represent circuit remediation activities, and costs for the second year of a project reflect substation remediation activities.[280] The estimated distribution cost with impacted circuit cutovers is calculated for each circuit based on the total number of distribution transformers associated with the circuit.[281] SCE states that it uses a blended unit cost of $66,400 per distribution transformer based on 2018-2021 recorded costs.[282] The total estimated distribution cost is derived by the aggregation of costs for circuit cutovers associated with each substation.[283] The substation and distribution unit costs utilized by SCE to calculate estimated 4-kV system remediation costs are

[276] Ex. SCE-02, Vol. 1, Pt. 2 at 152.

[277] Ex. SCE-02, Vol. 1, Pt. 2 at 152.

[278] Ex. SCE-13, Vol. 1 at 7.

[279] Ex. SCE-02, Vol. 1, Pt. 2 at 154-156, Tables II-38 and II-39.

[280] Ex. SCE-02, Vol. 1, Pt. 2 at 154.

[281] Ex. SCE-02, Vol. 1, Pt. 2 at 156.

[282] Ex. SCE-02, Vol. 1, Pt. 2 at 157.

[283] Ex. SCE-02, Vol. 1, Pt. 2 at 156-157.

based on historical recorded costs.[284] The forecast for standalone (partial or full) cutovers on 4-kV circuits due to load growth is a dollar amount per year, without further explanation.[285]

7.2.3.4. Polychlorinated Biphenyls Transformer Removal Program

As part of the Polychlorinated Biphenyls (PCB) Transformer Removal Program, SCE intends to replace approximately 440 distribution line transformers suspected of being contaminated with PCB oil greater than 50 parts per million (ppm). PCBs have dangerous effects on human health and the environment. SCE currently operates pre-1980 distribution transformers with the potential for containing PCBs. The Environmental Protection Agency (EPA) has encouraged all utilities to remove transformers containing significant levels of PCBs.[286] SCE states that the scope of the PCB Transformer Removal Program reflects resource availability and mitigates near-term safety risks. SCE also states the program directly aligns with current EPA guidance for the reduction of PCBs in the environment.[287]

For 2023-2025, SCE forecasts $5.964 million in costs associated with the PCB Transformer Removal Program.[288] SCE states that the forecast method for the PCB Transformer Removal Program is the average unit cost for replacing a PCB transformer multiplied by the anticipated number of PCB transformers to be

[284] Ex. SCE-02, Vol. 1, Pt. 2 at 157.

[285] Ex. SCE-02, Vol. 1, Pt. 2 at 155, Table II-38.

[286] Ex. SCE-02, Vol. 1, Pt. 2 at 160.

[287] Ex. SCE-02, Vol. 1, Pt. 2 at 163.

[288] Ex. SCE-13 Vol. 1, at 7. *See also* Ex. SCE-11 at B-1

replaced for each year in the 2023-2028 forecast.[289] SCE also states that different average unit costs are provided for overhead transformers, padmount transformers, and buried underground residential distribution transformers.[290] SCE states that the proposed expenditures are based on a 10-year forecast and recorded historical annual spending of approximately $2 million,[291] and unit costs were calculated using the historical recorded costs from 2022.[292] The costs associated with the PCB Transformer Removal Program are unopposed.

7.2.3.5. Worst Performing Circuit Program

The Worst-Performing Circuit (WPC) Program targets circuits with the poorest historical reliability. In the 2021 GRC, the WPC Program was an activity included within the Worst Circuit Rehabilitation Program. Pursuant to D.16-01-008, an Annual Reliability Report is produced as part of an annual compliance requirement.[293] This report provides a list of WPCs, which are defined as the top one percent of the worst-performing circuits in SCE's system based on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).[294]

SCE states that the WPC Program evaluates all outages on a WPC to determine the best mitigations to improve reliability for customers experiencing service interruptions.[295] SCE testifies that underground equipment failure was

[289] Ex. SCE-02, Vol. 1, Pt. 2 at 162, Table II-41.

[290] Ex. SCE-02, Vol. 1, Pt. 2 at 162, Table II-41.

[291] Ex. SCE-02, Vol. 1, Pt. 2 at 163.

[292] Ex. SCE-02, Vol. 1, Pt. 2 at 163.

[293] Ex. SCE-02, Vol. 1, Pt. 2 at 123.

[294] Ex. SCE-02, Vol. 1, Pt. 2 at 123.

[295] Ex. SCE-02, Vol. 1, Pt. 2 at 124.

the leading contributor in 2021 for WPCs.[296] SCE also testifies that aging cable is one of the main drivers for underground equipment failure. SCE expects to remediate approximately 71 circuits annually beginning in 2025, based on the seven-year average of the one percent of circuits that experienced the highest annual SAIDI and SAIFI.[297]

From 2023-2025, SCE forecasts $49.364 million in costs associated with the WPC Program. SCE states the forecast method for the WPC Program is the average unit cost for addressing a WPC multiplied by the anticipated number of WPCs to be addressed for each year in the 2023-2028 forecast.[298] SCE also states the average unit cost for addressing a WPC is based on the most recent completed work orders in 2021, then escalated to 2022 dollars.[299] The costs associated with the WPC Program are unopposed.

7.2.4. Climate Adaptation and Vulnerability Assessment

7.2.4.1. Climate Adaptation and Vulnerability Assessment Distribution Infrastructure Replacement

SCE's recent CAVA filing documents address how projected changes in climate may impact utility assets, operations, and services. SCE states that its proposed CAVA Distribution Infrastructure Replacement projects will be in identified areas where infrastructure is expected to experience increasing heat- and flooding-related events, both of which adversely impact distribution infrastructure in ways that can cause outages. SCE states it intends to align

[296] Ex. SCE-02, Vol. 1, Pt. 2 at 126.

[297] Ex. SCE-02, Vol. 1, Pt. 2 at 127.

[298] Ex. SCE-02, Vol. 1, Pt. 2 at 128, Table II-31.

[299] Ex. SCE-02, Vol. 1, Pt. 2 at 128.

climate adaptation into traditional planning processes to better embed climate considerations into core planning programs.[300]

SCE testifies that pad-mounted distribution equipment is sensitive to flooding because it has non-waterproof electrical components. SCE also testifies that it plans to replace 160 mainline pad-mounted air-insulated switches with flood-resistant equivalents. SCE is prioritizing mainline pad-mounted switches because they have a longer geographic reach and are critical to maintaining electric service.[301]

SCE also testifies that electrical transformers are sensitive to temperature and undergo stress due to heatwaves. SCE states that this is particularly the case when they are unable to sufficiently cool down overnight. This leads to faster degradation and transformer failure.[302] SCE states it is proactively planning a replacement program targeting 615 distribution service transformers where heat stress is likely to be most impactful. SCE also states that reliability is the primary driver for the proposed CAVA distribution infrastructure replacement programs.[303]

The forecast costs for the CAVA Distribution Infrastructure Replacement Program are $2.080 million. SCE states that the forecast method for the CAVA Distribution Infrastructure Replacement projects is the average unit cost for replacing a switch or transformer multiplied by the anticipated number of switches or transformers to be replaced for each year in the 2023-2028 forecast.

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[300] Ex. SCE-02, Vol. 1, Pt. 2 at 165.

[301] Ex. SCE-02, Vol. 1, Pt. 2 at 166.

[302] Ex. SCE-02, Vol. 1, Pt. 2 at 167.

[303] Ex. SCE-02, Vol. 1, Pt. 2 at 168-171.

SCE states that different average unit costs are provided for switches and transformers.[304] The average padmount switch unit cost is based on the unit cost estimated in 2022.[305] The costs associated with the CAVA Distribution Infrastructure Replacement Program are unopposed.

7.2.5. Parties' Positions on the DIR Program

7.2.5.1. Cal Advocates

Cal Advocates recommends overall capital-expenditure reductions for 2023, 2024, and 2025. Cal Advocates recommends the Commission adopt the following overall DIR capital expenditures: $779.739 million for 2023, $854.166 million for 2024, and $1,380.697 million for 2025. Cal Advocates also provides recommended adjustments to specific programs, which we discuss below.

UCR Program: As stated above, SCE's UCR Program forecasts $14.072 million recorded in 2023, $5.767 million for 2024, and $98.632 million for 2025. In response to SCE's UCR Program forecasts, Cal Advocates' corresponding forecasts are $10.433 million for 2023, $5.551 million for 2024, and $74.217 million for 2025.[306]

Cal Advocates' most significant reduction is the 2025 forecast for the UCR Program. Cal Advocates disagrees with SCE's plan to replace 400 conductor miles of underground cables in 2025.[307] For 2025, Cal Advocates recommends that a 300-conductor-mile replacement level be adopted. Cal Advocates argues

[304] Ex. SCE-02, Vol. 1, Pt. 2 at 172, Table II-42.

[305] Ex. SCE-02, Vol. 1, Pt. 2 at 173.

[306] Ex. CA-03 at 14.

[307] Cal Advocates OB at 26.

that this strikes an appropriate balance between risk reduction and cost.[308] Cal Advocates also reasons that there are diminishing risk reduction gains as the quantity of cable replacements increase.[309] Thus, Cal Advocates concludes that a 300 mile per year replacement forecast totaling 1,200 miles over the four-year period 2025 through 2028 is more reasonable, and will result in a safety and reliability risk reduction of 75 percent when compared to SCE's 1,600 miles and 80 percent risk reduction.[310]

CIC Replacement Program: As stated above, SCE's CIC Replacement Program forecasts $6.955 million recorded in 2023, $6.992 million for 2024, and $62.467 million for 2025. Cal Advocates recommends the following adjustments for the CIC Replacement Program: $5.738 million for 2023, $6.912 million for 2024, and $41.823 million for 2025.[311] Cal Advocates' largest forecast adjustment, in 2025, is $20.644 million less than SCE's forecast.

Cal Advocates asserts that it does not oppose SCE's replacement of 480 conductor miles of CIC cable from 2025-2028.[312] However, Cal Advocates recommends that the 480-mile replacement total be spread evenly over the four-year period.[313] In essence, Cal Advocates recommends replacing 120 miles per year over the 2025 through 2028 period totaling 480 conductor miles.[314] Cal Advocates asserts its approach strikes a balance between previous

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[308] Ex. CA-03 at 16-17.

[309] Ex. CA-03 at 15.

[310] Ex. CA-03 at 16.

[311] Ex. CA-03 at 18-19.

[312] Cal Advocates OB at 30.

[313] Ex. CA-03 at 18-19.

[314] Ex. CA-03 at 19-20.

replacement levels of 50-year old or more CIC cable and SCE's proposed forecast.[315]

OCP: As stated above, SCE's OCP forecasts are $70.796 million recorded in 2023, $62.874 million for 2024, and $332.799 million for 2025. Cal Advocates recommends OCP forecasts of $66.182 million in 2023, $55.221 million in 2024, and $244.920 million in 2025.[316] Compared with SCE's forecasts, Cal Advocates' forecasts are $0.096 million less than SCE's forecast for 2023, $7.653 million less for 2024, and $87.879 million less for 2025.

As stated above, OCP replaces bare conductor with covered conductor to mitigate the risks associated with energized downed overhead conductor. While SCE proposes to replace a total of 1,680 circuit-miles of overhead cable over the four-year period of 2025 through 2028, Cal Advocates proposes reducing the miles of replaced conductor.[317] Cal Advocates recommends SCE replace a total of 1,280 miles over the four-year period of 2025 through 2028.[318] This amounts to a 320 mile-per-year replacement forecast rather than a 420 mile-per-year replacement forecast. Cal Advocates states that this amounts to a 24 percent risk reduction rather than a 29 percent risk reduction as SCE proposes.[319]

Next, Cal Advocates proposes to reduce the unit cost for covered conductor that SCE uses to calculate its OCP forecast to $649,000 per mile from $663,000.[320] Cal Advocates asserts that it applies the imputed authorized unit

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[315] Ex. CA-03 at 19.

[316] Ex. CA-03 at 21.

[317] Ex. CA-03 at 24-25.

[318] Ex. CA-03 at 24-25.

[319] Cal Advocates OB at 37-38.

[320] Ex. CA-03 at 24-25.

cost for covered conductor in connection with the WCCP in Track 4 of SCE's 2021 GRC.[321] Finally, Cal Advocates argues that SCE's AOCP is unreasonable because it changes from year to year.[322] Cal Advocates asserts that SCE's AOCP forecasts are unsupported and unjustified and recommends adjusting the AOCP forecasts to $5.530 million for 2024 and $5.665 million for 2025.[323]

4-kV Remediation: Cal Advocates recommends the following forecasts for the 4-kV Remediation program: $42.605 million for 2023, $43.144 million for 2024, and $122.331 million for 2025.

Cal Advocates states it opposes the portion of SCE's 4-kV Remediation program tied to load growth.[324] Specifically, Cal Advocates opposes the methodology SCE used to derive the Load Growth costs associated with the 4-kV Remediation request.[325] Thus, Cal Advocates recommends the Commission use SCE's own 2023 Load Growth forecast as the foundation for determining the 2024 and 2025 forecasts rather than averages to project expenditures.[326]

7.2.5.2. TURN

Like Cal Advocates, TURN recommends reductions to the costs associated with the DIR Program. Generally, TURN argues that the record evidence demonstrates that SCE's customers did not experience significant declines in the utility's reliability or safety performance during the years of lower spending.[327]

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[321] Ex. CA-03 at 25-26.

[322] Ex. CA-03 at 26-27.

[323] Cal Advocates OB at 42.

[324] Cal Advocates OB at 43.

[325] Ex. CA-03 at 32.

[326] Ex. CA-03 at 32-35.

[327] TURN OB at 70-71.

TURN asserts that SCE spent $500 million per year during the 2014-2018 period, and SCE recorded approximately $200 million per year for DIR spending in 2021 and 2022.[328] TURN argues that for the 2025 TY, and the remainder of the upcoming GRC period, SCE forecasts spending a total of approximately $700-$800 million.[329] Thus, TURN argues even if the overall 2025-2028 DIR spending is consistent with historical levels, this does not satisfy SCE's burden of demonstrating its proposed spending is reasonable.[330]

Next, TURN argues the models SCE used to develop its DIR Program forecasts rest solely on a theoretical model lacking detailed, asset-specific historical data to substantiate an evidence-informed rate or frequency of replacement.[331] TURN argues that these models should operate with transparency and undergo independent peer reviews to ensure their methodologies are both understandable and verifiable.[332] TURN asserts that SCE has not met its burden to substantiate its DIR Program request. We discuss TURN's positions in further detail, below.

UCR Program: As discussed above, SCE proposes 1,600 miles of cable replacement from 2025-2028 to achieve 60-70 percent of the safety and reliability benefits according to its machine model for UCR. TURN, on the other hand, proposes 800 miles of cable replacement and recommends an authorized program cost of $214.631 million against SCE's $413.057 million.[333]

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[328] TURN OB at 70-71.

[329] TURN OB at 71.

[330] TURN RB at 31.

[331] TURN OB at 71.

[332] TURN OB at 72.

[333] Ex. TURN-05E at 55

In support of its adjustment to the UCR program, TURN states that the steepest safety and reliability benefit versus miles replaced is expected for the first 800 miles of underground cable. TURN reasons that most of the projected benefits from underground cable replacement may be achieved by replacing fewer miles than SCE recommends.[334] Additionally, TURN argues that UCR overlooks the multifaceted nature of underground cable failures and a more nuanced response may include conducting root cause analysis for component failures, cable loading, and water intrusion as a lower-cost alternative to wholesale replacement.[335]

OCP: As stated above, in this GRC period, SCE's OCP is targeting higher-risk overhead conductors in non-high fire risk areas (non-HFRA) and in HFRA that are not included in SCE's WCCP.[336] For 2025-2028, SCE plans to deploy covered conductor for 420 circuit miles annually, totaling 1,680 circuit miles.[337] SCE estimates this may mitigate approximately 30 percent of the risk associated with primary overhead conductor by the end of the GRC period.[338] SCE requests approximately $1.349 billion to support OCP from 2025-2028.[339]

TURN recommends the Commission substantially reduce SCE's request for its non-HFRA OCP. TURN asserts that the Commission should authorize $396.516 million for OCP, which is a reduction of $1.086 billion from SCE's forecast and request. In support of its position, TURN argues that OCP's

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[334] Ex. TURN-05E at 58.

[335] Ex. TURN-05E at 57.

[336] Ex. SCE-02, Vol. 1, Pt. 2 at 83.

[337] Ex. SCE-02, Vol. 1, Pt. 2 at 95.

[338] Ex. SCE-02, Vol. 1, Pt. 2 at 95.

[339] Ex. SCE-13, Vol. 1 at 24.

spending level is unduly burdensome and OCP would not achieve the project safety and reliability benefits that SCE claims could be achieved. [340]

Second, TURN argues that the proposed scale of OCP represents a 133 percent increase in forecasted costs compared to the 2017-2022 period.[341] TURN testifies that covered conductor is one of the costliest mitigation measures available to the utility and should be used only where less costly alternatives are inadequate. TURN also points out that the cost of covered conductor is one cost concern that triggers others. For example, TURN states that covered conductor is approximately 1.5 to 1.9 times heavier than bare conductor, increasing the likelihood that a reconductoring project will also need to include replacement of poles and other equipment sized for bare conductor, but inadequate for covered conductor.[342]

Third, TURN asserts the reliability benefits of covered conductor as compared to bare conductor are exaggerated. TURN argues that SCE has not adequately analyzed covered conductor's safety and reliability benefits, and SCE's reliability data is improving with the current infrastructure replacement programs without the proposed shift to covered conductor in non-HFRA areas.[343]

Fourth, TURN has several concerns with SCE's machine learning-based modeling that informed the development of the proposed scope and prioritization of OCP. TURN argues that SCE's reliance on machine learning

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[340] Ex. TURN-05E at 42-43.

[341] Ex. TURN-05E at 41-45.

[342] TURN OB at 76.

[343] Ex. TURN-05E at 46-47.

models is opaque and going forward, SCE should test multiple models, show confidence intervals and ranges in results, and demonstrate the final model's performance against other potential models.[344]

7.2.5.3. CUE

For its part, CUE supports SCE's DIR requests. CUE states that SCE's forecasts in this GRC reflect the minimum amount of work the Commission should require SCE to complete over the next four years.[345] CUE recommends that the Commission fully fund SCE's distribution and substation infrastructure replacement programs. Furthermore, CUE recommends that in the 2029 GRC cycle, the Commission should hold SCE accountable for achieving a steady-state replacement rate across its infrastructure replacement programs. We discuss CUE's recommendations in further detail, below.

UCR: CUE recommends the Commission approve the UCR forecast and eliminate restrictions on replacing cables younger than 41 years old. CUE supports SCE's $400.250 million request to support UCR work from 2025 through 2028. CUE asserts that the Commission should, at a minimum, approve SCE's UCR program forecast, which will increase proactive replacement of aging and high-risk underground cables. CUE also recommends that the Commission eliminate restrictions that prevent SCE from replacing cables younger than 41 years old since these cables have an average failure age of 38 years. CUE testifies that these recommendations will improve grid safety and reliability, and allow

[344] TURN OB at 81.

[345] CUE OB at 6.

SCE to ramp up replacement efforts in the next GRC cycle consistent with a steady-state replacement rate.[346]

In response to Cal Advocates, CUE argues that Cal Advocates' proposed budget is 37.3 percent below SCE's recorded spending for 2018 in nominal terms. CUE also testifies that Cal Advocates' proposal results in replacing existing underground cable by the year 2245.[347] CUE states that under Cal Advocates' proposal, cable installed in the year 2245 will be 220 years old, rendering Cal Advocates' recommendation unreasonable for the Commission to consider credible. CUE asserts that Cal Advocates' reduction is based on an increase in the forecast rate and ignores the fact that replacement rates were reduced in the last GRC to focus on wildfire mitigation. CUE also argues that Cal Advocates ignores the fact that there has been an intervening period where resources have been refocused on wildfire prevention.[348] In short, CUE recommends the Commission reject Cal Advocates' proposal.

In response to TURN, CUE opposes TURN's proposals. First, CUE testifies that TURN inappropriately compares the 2018-2022 expenditures to the proposed expenditures, not considering the fact that resources were diverted to wildfire prevention with the understanding that safety and reliability would decrease.[349]

Second, CUE argues that TURN bases its proposal on the idea of diminishing returns. CUE states that there may be some credibility to TURN's

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[346] CUE OB at 8.

[347] Ex. CUE-02 at 15.

[348] Ex. CUE-02 at 15.

[349] Ex. CUE-02 at 15.

position that often, given appropriate prioritization, more is achieved per dollar in the first 70 percent of risk reduction versus the next 10 percent of risk reduction. However, CUE argues that TURN does not provide a reason why its 70 percent stopping point is reasonable, especially in light of the fact that under its proposal, the steady-state replacement cycle will require 303 years, or eight times the average cable age at failure.[350] CUE asserts that the average failure age of underground cable is 38 years. Even doubling the minimum replacement age from the average failure age to 76 years implies a steady-state replacement rate of 868 miles per year. CUE states that this is more than double SCE's proposal.[351] In short, CUE recommends the Commission reject Cal Advocates' and TURN's proposed reductions.

CIC: CUE opposes Cal Advocates' recommendation to spread out the CIC program. CUE argues that Cal Advocates' proposal is based on a misconception. CUE states it appears that Cal Advocates did not realize that SCE structured this program so that the total miles of CIC replaced, both older than 50 years and between 25 to 50 years, adds up to 180 miles per year. CUE states SCE's proposal, beginning in 2025, replaces 180 miles older than 50 years, and thereafter, SCE proposes to replace 100 miles of CIC older than 50 years and 80 miles of CIC between 25 and 50 years. Thus, CUE asserts that Cal Advocates' proposal to spread out the work in the CIC program is based on a misconception and should be rejected.[352]

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[350] Ex. CUE-02 at 16.

[351] Ex. CUE-02 at 16.

[352] Ex. CUE-02 at 17.

OCP: CUE opposes Cal Advocates' reduction in circuit miles. CUE asserts that Cal Advocates' reasoning does not support its recommendation.[353] CUE states that contrary to Cal Advocates' assertion of declining marginal returns, the data it presents show an ambiguous picture of the incremental returns being constant at three percent twice, dropping to two percent, then increasing to three percent and returning to two percent. CUE argues that this is not an example of marginal declining returns. Furthermore, CUE points out that Cal Advocates stops at 1,280 miles with an incremental value of two percent. CUE testifies that the next value of 1,480 has an incremental value of three percent and, if Cal Advocates is concerned about the marginal returns, it would logically recommend at least 1,480 miles because of the increased marginal return.[354]

CUE also opposes Cal Advocates' proposed reduction of 100 circuit miles per year to OCP. CUE argues that Cal Advocates completely ignores the fact that OCP was reduced so that SCE could focus on wildfire mitigation.[355] CUE recommends the Commission reject Cal Advocates' proposal to cut 100 miles per year from OCP.

With respect to TURN, CUE recommends that the Commission reject TURN's opposition to the proactive replacement of aging or faulty overhead cable simply because TURN fears that the OCP will become a recurring ask.[356] CUE testifies that TURN's proposal to authorize only 106 miles of overhead cable to be replaced annually from 2025 to 2028 is less than a third of that replaced in

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[353] Ex. CUE-02 at 23.

[354] Ex. CUE-02 at 23.

[355] Ex. CUE-02 at 23-24.

[356] Ex. CUE-02 at 21.

2018 before SCE began its focus on wildfire issues.[357] CUE states that TURN's proposal is unreasonable and should be rejected.

4-kV Remediation Program: CUE opposes Cal Advocates' recommendation to reduce the 4-kV Remediation Program. CUE asserts that Cal Advocates' proposal is unsupported and should be rejected. CUE states that in previous years, SCE has done fewer 4-kV remediation projects since 2018 because it kept focus on wildfire mitigation activities.[358] Now, increased investment in 4-kV remediation work is important, and SCE's forecast request is necessary to help SCE meet its duty to serve and duty to support state electrification efforts on a timeline consistent with state decarbonization commitments.[359]

7.2.5.4. EPUC

EPUC opposes SCE's DIR OCP request. Generally, EPUC argues that SCE's DIR capital program is unreasonable and without merit when viewed within the context of SCE's entire GRC spending plans.[360] We discuss EPUC's recommendations to reduce OCP, below.

OCP: EPUC argues SCE has not provided adequate justification for accelerating capital investments to mitigate the risk of wire-down events.[361] EPUC asserts that while reducing these events would be in the public interest, such reductions should be made at reasonable costs to manage rate affordability. EPUC states that SCE data shows wire-down events for non-HFRAs have been

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[357] Ex. CUE-02 at 22.

[358] Ex. CUE-02 at 19-20; *see also* CUE OB at 10-11.

[359] CUE OB at 10-11.

[360] EPUC RB at 6-7.

[361] Ex. EPUC-01 at 20.

relatively stable over the period 2018-2022.[362] EPUC also states that SCE is proposing significant wildfire grid investments and there is a need for managing rate affordability. EPUC recommends SCE should limit OCP capital investments to at-risk circuits and implement other measures to mitigate public risk in the event of wire-down events. EPUC argues that SCE can achieve its OCP objectives by extending the capital plan from a targeted 2028 completion date to 2035. EPUC testifies that the extended timeline would reduce the GRC revenue increase SCE claims is required, and moderate the increase in SCE's rates that will be needed to pay for these capital investments.[363] EPUC recommends that the Commission adopt TURN's proposal to limit the OCP to small-gauge wires.[364]

7.2.5.5. SCE's Rebuttal

In response to the parties' positions, SCE argues that the DIR request is within the historical parameters of previous levels of recorded capital expenditures. SCE asserts that those historical levels of spending had to be reduced beginning in 2018 to allow SCE to reallocate resources to address emergent statewide wildfire threats, primarily for its WCCP.[365] In other words, SCE testifies that its DIR forecast in 2025 is fundamentally a return to traditional and previously recorded levels. SCE also testifies that it is seeking to resume DIR activities to essentially the level that SCE recorded in 2018 — a level that was generally deemed by the Commission to be prudent and reasonable to address

[362] Ex. EPUC-01 at 20.

[363] Ex. EPUC-01 at 22.

[364] EPUC RB at 15.

[365] SCE OB at 27-28.

public safety and reliability risks.[366] SCE testifies that the wildfire system hardening that it conducted in the WCCP program was urgently needed to address the near-existential threat of wildfire — which was endorsed by SCE's regulator approved WMP at a time of state-wide labor shortages needed for overhead system hardening work.[367] SCE reasons that because the WCCP program is beginning to wind down, resources are again available to resume traditional levels of DIR work.[368]

7.2.5.5.1. OCP Rebuttal

In response to Cal Advocates' positions, SCE argues that its OCP forecast is reasonable and risk-formed. SCE states that OCP was introduced in SCE's 2018 GRC as a hallmark program to address the serious public safety risks associated with energized downed overhead conductor. SCE also states that it will be updating its OCP deployment strategy for years 2025 and beyond.[369] SCE's previous approach for the OCP was to utilize bare wire conductor when replacements occurred. However, based on more recent and refined analysis of the drivers of conductor failure events, SCE plans to replace bare conductor with covered conductor as the primary mitigation for the risks that OCP is comprehensively designed to address. [370]

SCE contends that Cal Advocates essentially proposes trading off increased public safety via SCE's OCP in exchange for cost reduction. SCE contends that Cal Advocates did not provide any risk-informed justification for

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[366] Ex. SCE-13, Vol. 1 at 4.

[367] SCE OB at 28-29.

[368] Ex. SCE-13, Vol. 1 at 5.

[369] Ex. SCE-02, Vol. 1, Pt. 2 at 90-94.

[370] Ex. SCE-02, Vol. 1, Pt. 2 at 90-94.

selecting its proposed scope-only pointing to affordability concerns.[371] SCE asserts that it is also focused on customer affordability and is only requesting funding in this GRC cycle for remediating the riskier portions of its overhead conductor inventory in the OCP that account for 29 percent of the risk.[372]

Next, SCE argues that Cal Advocates' proposed reduction to OCP's program size leaves a significant amount of risk unmitigated. SCE asserts that if the Commission adopts Cal Advocates' proposal, 400 circuit miles would remain unmitigated in this GRC cycle. This scope is estimated to equate to more than 11.5 million customer minutes of interruption.[373] SCE states that its request to cover 1,680 miles across this GRC cycle equates to less than six percent of SCE's OCP inventory, while reducing nearly 30 percent of the risk.[374]

With respect to TURN, SCE asserts that its recommendation to reject the entire proposed scope of OCP, except the AOCP, is draconian. SCE states that TURN has acknowledged the necessity of evidence informed infrastructure replacement to ensure a safe and reliable electric grid and agreed that contact with energized wire-down events poses a grave safety threat.[375] SCE testifies that if TURN's position is adopted it would significantly reduce SCE's UCR and OCP scope by 50 percent and 75 percent, respectively.[376]

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[371] SCE OB at 33.

[372] Ex. SCE-13, Vol. 1 at 11.

[373] Ex. SCE-13, Vol. 1 at 12.

[374] Ex. SCE-13, Vol. 1 at 12.

[375] SCE OB at 37-38.

[376] Ex. SCE-13, Vol. 1 at 23.

SCE also testifies that TURN's position severely limits its ability to mitigate risk, including the risk of property fires, wildfires, injuries, and fatalities.[377] SCE states that TURN's proposal to reject the entirety of the OCP scope, less the AOCP forecast, is based on flawed reasoning and incorrect conclusions. SCE makes the following assertions: (1) its methodology for using serious injury or fatality data is reasonable and appropriate for risk modeling;[378] (2) TURN's criticisms of SCE's OCP-specific models lack merit;[379] (3) TURN incorrectly argues that SCE lacks a covered conductor forecast outside of HFRA;[380] (4) TURN's concerns about potential reoccurring requests have no bearing on the reasonableness of SCE's OCP forecast;[381] (5) TURN inaccurately describes the benefits and scope of appropriate use of covered conductor;[382] (6) TURN makes misplaced assumptions regarding the limits and performance of covered conductor;[383] (7) the reliability benefits of OCP are not exaggerated;[384] and (8) both large-gauge and small gauge wires are appropriate in OCP.[385]

Finally, with respect to EPUC's position that SCE should limit OCP's size and scope, SCE asserts that it is targeting 1,680 circuit miles of the highest risk of its overall overhead conductor inventory to reduce risk associated with overhead

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[377] Ex. SCE-02, Vol. 1, Pt. 2 at 8-9.

[378] Ex. SCE-13, Vol. 1 at 31-43.

[379] Ex. SCE-13, Vol. 1 at 32-33.

[380] Ex. SCE-02, Vol. 1, Pt. 2 at 95.

[381] SCE OB at 45.

[382] Ex. SCE-13, Vol. 1 at 34-39.

[383] Ex. SCE-13, Vol. 1 at 34-39.

[384] Ex. SCE-13, Vol. 1 at 40.

[385] Ex. SCE-13, Vol. 1 at 40-43.

conductor by roughly 30 percent.[386] Thus, SCE testifies that it is already targeting at-risk segments as requested by EPUC.

7.2.5.5.2. Accelerated OCP

In response to Cal Advocates, SCE asserts that its forecast is reasonable and based on 2023 recorded expenditures and 2018-2022 historical averages. SCE testifies that its AOCP forecast is generally based on the typical ratio of OCP to AOCP. SCE's 2025-2028 forecast includes an AOCP forecast of four percent of the OCP forecast in a given year.[387] Thus, SCE asserts that it has demonstrated that its recorded expenditures for 2023 are aligned with the 2018-2022 historical average of four percent.[388]

7.2.5.5.3. UCR Rebuttal

SCE asserts that its UCR forecast is prudent and risk-informed. In response to Cal Advocates, SCE states a gradual diminished return in the percentage of risk reduction of the GRC period is normal and the mathematical result of completing a risk-informed scope of work in a risk-prioritized manner.[389] SCE also asserts that the imposition of an antiquated age limit on underground cable replacement hampers its ability to fully address the relevant risks and thus, the age restriction should be lifted.[390]

With respect to TURN, SCE asserts that its recommendation to cut the scope of UCR in half — 800 miles over the period from 2025 to 2028 rather than the 1,600 miles that SCE proposed — leaves customers unnecessarily exposed to

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[386] Ex. SCE-13, Vol. 1 at 47.

[387] Ex. SCE-13, Vol. 1 at 14.

[388] Ex. SCE-13, Vol. 1 at 14.

[389] Ex. SCE-13, Vol. 1 at 15.

[390] Ex. SCE-02, Vol. 1, Pt. 2 at 37-38; *see also* Ex. SCE-13, Vol. 1 at 16-20.

avoidable risk.[391] SCE states that according to TURN's own analysis, there were over 11,700 cable and component failures from 2013-2022 or on average, roughly 1,170 annually.[392] SCE states that this is an unacceptable level of cable and component failures and highlights the need to fully adopt SCE's UCR request to proactively address these in-service failures.[393] SCE argues that it has demonstrated how its UCR Program efficiently replaces associated components at the same time as it replaces cable, mitigating the safety and reliability risks associated with both simultaneously.[394] SCE argues that unlike TURN, its approach to UCR considers and appropriately addresses mainline cable and components as an integrated system.[395]

7.2.5.5.4. CIC Rebuttal

In response to Cal Advocates, SCE states that in this GRC, SCE's CIC replacements spring from two sources: (1) CIC miles between 25-50 years of age that failed the concentric neutral degradation evaluation (*i.e.*, deemed ineligible for life-extending injection in SCE's CLE Program); and (2) CIC miles greater than 50 years of age targeted for replacement (*i.e.*, targeted by risk models).[396] SCE states that its forecast includes 240 and 480 miles from these two activities respectively — 720 miles combined — over the four years. SCE points out that 240 miles of CIC replacement scope is fed by SCE's CLE Program activity which is resuming in 2025. Thus, SCE states 2026 represents the earliest replacement

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[391] SCE OB at 50.

[392] Ex. SCE-13, Vol. 1 at 45.

[393] SCE OB at 51.

[394] SCE OB at 51.

[395] SCE OB at 51.

[396] Ex. SCE-02, Vol. 1, Pt. 2 at 46-52.

date for these 240 CIC miles, making Cal Advocates' recommendation to evenly spread these miles impossible.[397]

SCE also asserts that its CIC forecast already evenly spreads the total 720 miles of total CIC scope at a rate of 180 miles per year.[398] SCE contends that the 180 miles in 2025 that Cal Advocates calls a replacement peak is actually the first 180 miles of SCE's 720 CIC mile replacements.[399] SCE asserts that implementing Cal Advocates' recommendation would result in an uneven spread of these miles of CIC scope across the four years.

7.2.5.5.5. 4-kV Program Remediation

In response to Cal Advocates' 4-kV Remediation Program recommendation, SCE asserts that Cal Advocates does not acknowledge that transportation electrification load growth is accelerating and the drivers for this growth prominently include state policies.[400] SCE argues that its 4-kV systems are inherently limited in their capacity to serve customers since they were installed between 60-80 years ago with drastically different customer and grid needs in mind. SCE states that these limitations exist on every 4-kV circuit on SCE's system and continue to result in delays for customers served by 4-kV circuits.[401] This restricts customers' ability to fully participate in the transition to

[397] Ex. SCE-13, Vol. 1 at 21.

[398] Ex. SCE-13, Vol. 1 at 21.

[399] Ex. SCE-13, Vol. 1 at 20-21.

[400] SCE OB at 37.

[401] Ex. SCE-13, Vol. 1 at 22.

a decarbonized economy.[402] Thus, SCE asserts that Cal Advocates' recommendation is unreasonable.[403]

7.2.6. DIR Discussion

Below, we address the uncontested areas of SCE's DIR Program. Then, we address the contested areas of DIR.

7.2.6.1. UCR Program Discussion

The Commission has two questions presented before it regarding the UCR Program. The first question is whether the Commission should adopt and authorize the UCR Program. The second question is, if the Commission does authorize and adopt the UCR Program, what the authorized funding should be.

First, we adopt and authorize the UCR Program. The UCR Program proactively targets the replacement of mainline underground cables and cable components. Over 45 percent of SCE's primary distribution system is sited underground. SCE testifies that since 2017, it has experienced approximately 1,300 underground cable failures annually due to equipment failure, component failure, cable loading, or water intrusion. These failures not only have reliability impacts but can lead to explosions, high temperature gas releases, and arc flashes which potentially have significant impact on the public as well as SCE employees.[404]

The UCR Program is a reasonable program to mitigate the safety and reliability risks associated with underground cable and component failure. Therefore, we authorize and adopt the UCR Program. The next question the

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[402] SCE OB at 37.

[403] SCE OB at 36-37.

[404] Ex. SCE-02, Vol. 1, Pt. 2 at 30.

Commission must answer is what the project scope of the UCR should be, and what forecasted costs the Commission should adopt.

Contextually, after several years of lower mileage replacement in its UCR program due to redirection of funding for wildfire mitigation efforts, SCE proposes to ramp up UCR to 400 miles annually for 2025-2028. SCE states that this will achieve approximately an 80 percent safety and reliability risk reduction. SCE also states that 400 conductor miles per year aligns with its historical averages. CUE supports SCE's proposal, asserting that SCE's proposal is the bare minimum SCE should adopt.[405] However, some parties propose reductions to the scope of UCR which reduce the associated costs.

First, Cal Advocates proposes reductions to UCR's scope. Cal Advocates recommends using a replacement rate of 300 conductor miles per year, totaling 1,200 miles over this GRC cycle, to strike a balance between risk reduction and costs. Cal Advocates asserts that its proposal results in a safety and reliability risk reduction of 75 percent compared to SCE's 1,600 miles and 80 percent risk reduction.[406] In support of its position, Cal Advocates makes an array of arguments. First, Cal Advocates argues that the full program forecast is not justified by the incremental risk reduction.[407] Second, Cal Advocates asserts that there is a gradually diminishing return in the percentage of risk reduction over the GRC period.[408] Third, Cal Advocates asserts that its approach saves ratepayers money.[409]

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[405] Ex. CUE-02 at 14.

[406] Ex. CA-03 at 16.

[407] Ex. CA-03 at 17.

[408] Ex. CA-03 at 15-17.

[409] Cal Advocates OB at 27.

TURN, on the other hand, essentially cuts SCE's proposal in half. TURN proposes funding based on 800 miles of underground cable replacement, rather than the proposed 1,600 miles from SCE. TURN argues that this will still enable SCE to achieve 60-70 percent of the safety and reliability benefits it seeks while lowering the costs to ratepayers.[410]

SCE opposes both TURN's and Cal Advocates' recommendations. SCE argues that Cal Advocates' analysis does not fully consider the overall benefits of the program.[411] SCE also states that there are gradual, diminishing returns in the percentage of risk reduction over the GRC period because that is the normal, mathematical result of completing a risk-informed scope of work in a risk-prioritized manner. SCE calculates its relative risk reductions as follows: (a) 400 circuit-miles achieves 54 percent safety and reliability risk reduction in 2025; (b) 400 circuit-miles achieves 14 percent safety and reliability risk reduction in 2026; (c) 400 circuit-miles achieves seven percent risk reduction in 2027; and (d) 400 circuit-miles achieves five percent risk reduction in 2028. SCE prioritizes the riskiest circuit miles first; and the risk reduction from the last 400 miles in SCE's forecast is still meaningful to SCE's customers for reliability and safety.[412] With respect to TURN, SCE argues that TURN's proposal to halve the size of the program during the next GRC period would leave customers unnecessarily exposed to avoidable risk.[413]

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[410] TURN OB at 83-84.

[411] Ex. SCE-13, Vol. 1 at 15.

[412] Ex. SCE-13, Vol. 1 at 16.

[413] Ex. SCE-13, Vol. 1 at 43.

Here, we weigh the relative risk reduction against the associated costs to lessen the rate impact upon SCE customers. Therefore, on balance, we adopt Cal Advocates' recommendation for UCR's project scope and costs. Cal Advocates' position is a reasonable, middle ground between SCE and the other intervenors. In lieu of a 400-mile-per-year replacement forecast, a 300-mile-per-year replacement forecast, totaling 1,200 miles over the four-year period from 2025-2028, is prudent and reasonable when compared to SCE's and TURN's positions. This achieves a balanced approach to safety and reliability risk reduction against capital expenditures in the TY. According to Cal Advocates, a 1,200 total conductor mile replacement will result in a safety and reliability reduction of 75 percent.[414] While this percentage is five percent less than SCE's proposed 80 percent risk reduction, we agree with Cal Advocates that 75 percent still prioritizes safety and provides a very significant risk and reliability improvement while also reducing capital expenditures to lessen the burden on customer rates.

Finally, SCE states that the 80 percent risk reduction SCE seeks to achieve in the 2025 GRC period is associated with mainline cable that is at least 41 years old.[415] SCE is currently prevented from replacing cable in the UCR Program that is younger than 41 years. SCE states that a blanket minimum age threshold for cable replacement is not the best predictor for addressing cable failure and asserts that there should no longer be a specified minimum age. SCE's average cable age is currently 38 years old, which is the average age that underground

[414] Ex. CA-03 at 17; *see also* Cal Advocates OB at 26.

[415] Ex. SCE-02, Vol. 1, Pt. 2 at 38.

cable fails.[416] We are unpersuaded at this time to remove the minimum age threshold. A threshold helps ensure there is a measure of cost control while maintaining the integrity of the system. If SCE would like the Commission to reconsider the prohibition on replacing cable less than 41 years old in SCE's next GRC, SCE should make its case more strongly there.

In conclusion, we find the UCR program reasonable and authorize and adopt it for SCE. We adopt and authorize the following cost forecasts for the UCR program to support a 300-mile-per-year replacement: (1) $14.072 million recorded for 2023; (2) $5.551 million for 2024; and (3) $74.217 million for 2025.

7.2.6.2. CLE Discussion

As discussed above, the CLE Program prolongs the life of CIC by injecting silicone-based fluid along the strands of the cable to fill voids in the CIC insulation. This process extends the life of the rejuvenated cable by approximately twenty years. SCE states that CIC that is eligible for the CLE Program must be between the ages of 25-50, targeted by the risk model, and have less than 50 percent concentric neutral degradation.[417]

SCE's undisputed 2023-2025 capital forecast for the CLE Program is $15.879 million, of which $0.026 million has been recorded in 2023, $0 is anticipated for 2024, and $15.853 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

7.2.6.3. CIC Replacement Program Discussion

The Commission has two questions presented before it regarding the CIC Replacement Program. The first question is whether the Commission should

[416] Ex. SCE-13, Vol. 1 at 16.

[417] SCE OB at 35.

adopt and authorize the CIC Remediation Program. The second question is, if the Commission does authorize and adopt this program, what should the authorized scope and funding be.

We authorize and adopt the CIC Replacement Program. The CIC Replacement Program focuses on rejuvenating and replacing radial underground cables and cable components in specific regions and sites within SCE's service territory based on safety and reliability risks.[418] Approximately 12,000 conductor miles, or one-fifth of SCE's cable population, is CIC.[419] The CIC Replacement Program addresses some of the challenges of an aging cable population.

The CIC Replacement Program will use two programs to mitigate the impacts associated with older and failing CIC. First, the CIC Replacement Program looks to prolong the life of CIC through the CLE Program.[420] This program targets CIC that is eligible for rejuvenation by injecting a silicone-based fluid along the strands of the cable to fill voids in the CIC insulation.[421] This fluid migrates into the conductor insulation, filling voids and modifying its chemistry to improve its dielectric strength.[422] This will allow this asset to remain in service and lessen the probability of failure.

Second, the CIC Replacement Program is used to replace segments that are older than 50 years of age because cables at this age do not meet the criteria for

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[418] Ex. SCE-02, Vol. 1, Pt. 2 at 42.

[419] Ex. SCE-02, Vol. 1, Pt. 2 at 52.

[420] Ex. SCE-02, Vol. 1, Pt. 2 at 48-52.

[421] Ex. SCE-02, Vol. 1, Pt. 2 at 42.

[422] Ex. SCE-02, Vol. 1, Pt. 2 at 42.

injection.[423] This replacement program is also utilized to address segments that fail during attempted CIC rejuvenation.

In essence, the objective of this program is to reduce the number of in-service failures of CIC and as a consequence, drive down the number of unplanned outages to SCE customers. SCE is proposing to replace 180 conductor miles per year, 2025 through 2028.[424]

No party opposes the CIC Replacement Program, or the activities proposed within it. However, Cal Advocates recommends that the 480-mile replacements for segments that are older than 50 years of age be spread evenly over the 2025-2028 year-period.[425] Specifically, Cal Advocates recommends replacing 120 miles per year over the 2025 through 2028 period, totaling 480 conductor miles, which Cal Advocates states equals the total quantity of CIC replacements that SCE requests.[426] Additionally, Cal Advocates expresses concern with SCE's forecast methodology, asserting the 2025 TY forecast for replacement of 180 miles of CIC at least 50 years old is partly derived from attrition-year forecasts.[427] Cal Advocates also states that SCE's methodology should not be precedent for future GRC capital investigations.[428]

For its part, SCE asserts that Cal Advocates contradicts its own recommendation of an even spread of CIC miles across the GRC cycle of the CIC scope. SCE argues that Cal Advocates' recommendation is silent about the

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[423] Ex. SCE-02, Vol. 1, Pt. 2 at 46-47.

[424] Ex. SCE-02, Vol. 1, Pt. 2 at 52.

[425] Ex.CA-03 at 18-19.

[426] Ex. CA-03 at 19-20.

[427] Cal Advocates OB at 32-35.

[428] Cal Advocates OB at 35.

remaining 240 miles of CIC scope between the ages of 25-50 years that are also in SCE's forecast but are ineligible for life-extending treatment through the CLE Program.[429] SCE contends that Cal Advocates does not explicitly reference these CIC replacement miles, and in so doing, Cal Advocates contradicts its own recommendation of an even spread of CIC miles across the GRC cycle.[430]

In support of SCE, CUE argues that SCE structured the program so that the total miles of CIC replaced, both older than 50 years and between 25 to 50 years, adds up to 180 miles per year. CUE testifies that SCE proposes to replace 180 miles older than 50 years, thereafter SCE proposes to replace 100 miles of CIC older than 50 years and 80 miles of CIC between 25 and 50 years. CUE argues that the recommendation to evenly spread out the work in the CIC program seems to be based on a misconception, and should be rejected. [431]

We authorize and adopt Cal Advocates' recommendation to replace 120 miles per year, for segments that are older than 50 years of age, over the 2025-2028 period, totaling 480 conductor miles, which equals the total quantity of CIC replacements that SCE requests. We find that Cal Advocates' recommendation to evenly spread out these additions, rather than having a replacement peak in 2025, is reasonable.

Therefore, we adopt Cal Advocates' recommended revisions to the CIC Replacement Program which results in forecasts for CIC replacements of $5.738 million in 2023, $6.912 million in 2024, and $41.823 million in 2025.

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[429] Ex. SCE-13, Vol. 1 at 20.

[430] SCE OB at 35-36.

[431] Ex. CUE-02 at 16-17.

7.2.6.4. Underground Switch Replacement Program Discussion

As discussed above, the Underground Switch Replacement Program replaces switches, approaching or exceeding the end of their service life, in underground structures to reduce risk to system reliability and public and employee safety. We find these activities reasonable, and we adopt SCE's 2023 recorded expenditures of $2.829 million as well as adopt Cal Advocates' forecasts of $3.242 million in 2024 and $13.382 million in 2025.[432] We find Cal Advocates' forecasts more accurate due to their inclusion of Errata changes that SCE provided in Ex. SCE-02, Vol. 01, Part 02 E, which results in lower costs for ratepayers because they reduce it slightly reduces the forecasted totals. Thus, we adopt and authorize a total of $19.453 million for the Underground Switch Replacement Program.

7.2.6.5. Underground Structure Replacement Program Discussion

As discussed above, the Underground Structure Replacement Program consists of three primary activities. The activities are: (1) structure replacements to install new structures where significant deterioration is observed; (2) structure shoring to extend the life of deteriorating structures when feasible; and (3) the CPRR program to reduce the consequences from vault explosions.

SCE's undisputed 2023-2025 capital forecast for the Underground Structure Replacement Program is $181.059 million of which $33.422 million was recorded in 2023, $58.709 million is anticipated for 2024, and $88.927 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

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[432] Ex. CA-03 at 20.

7.2.6.6. OCP Discussion

With respect to the OCP, the Commission has two questions presented before it. The first question is whether the Commission should adopt and authorize the OCP Program. The second question is, if the Commission does authorize and adopt the OCP Program, what the authorized funding should be.

The OCP was originally introduced in SCE's 2018 GRC to address public safety risks associated with energized downed overhead conductor. This program aims to mitigate these risks and other public safety risks as well as provide reliability benefits. SCE states that previously, its OCP strategy was to utilize bare wire conductor when replacements occurred. However, based on more recent and refined analysis of the drivers of conductor failure events, SCE plans to replace bare conductor with covered conductor as the primary mitigation for the risks that the OCP is comprehensively designed to address.[433]

To implement this in TY 2025-2028, SCE plans to deploy covered conductor for 420 circuit miles annually, totaling 1,680 circuit miles. This is estimated to mitigate approximately 29 percent of the risk associated with primary overhead conductor by the end of the GRC period.[434] TURN opposes SCE's request to authorize and implement OCP.[435] Cal Advocates recommends reducing the scope of OCP to 1,280 circuit miles over the four-year period from 1,680 circuit miles.[436]

TURN's proposal to reject the entirety of the OCP scope, with the exception of SCE's AOCP forecast, is predicated on several arguments. First,

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[433] Ex. SCE-02, Vol. 1, Pt. 2 at 90-94.

[434] Ex. SCE-02, Vol. 1, Pt. 2 at 95.

[435] TURN OB at 2.

[436] Cal Advocates OB at 36.

TURN asserts that SCE's OCP is not adequately supported. TURN argues that the Commission should deny OCP because SCE has not shown how this program complements other cable and conductor programs that could collectively enhance safety, and reliability benefits, attributable to OCP. For example, TURN states that SCE has not demonstrated that the associated safety and reliability benefits warrant including large gauge wires or how OCP complements other cable and conductor replacement programs.[437]

Second, TURN states that the spending request for OCP represents only a portion of the utility's total overhead reconductoring activities. TURN asserts that the Commission should be concerned with the proposed scale of the GRC proposed program.[438] According to TURN, SCE's proposal to replace 1,680 miles of fully functional overhead conductors represents a 133 percent increase in forecasted costs compared to the 2017-2022 period. TURN states that this sends SCE down an exceedingly costly path without a sufficient demonstration that the program is clearly cost-effective and otherwise reasonable.[439]

Cal Advocates, on the other hand, recommends scaling back OCP rather than an outright elimination of it. Cal Advocates states that SCE's 2025 forecast of 420 circuit-miles of replacements is over four times as much as its 2024 forecast.[440] Cal Advocates recommends that the Commission adopt a 320-mile-per-year replacement forecast, which totals 1,280 miles over the GRC period.[441] Cal Advocates states this results in a 24 percent risk reduction. The

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[437] TURN OB at 74.

[438] TURN OB at 75.

[439] TURN OB at 76.

[440] Cal Advocates OB at 37.

[441] Cal Advocates at 38.

next question is, how much risk should be driven down under the recommendations of SCE and Cal Advocates.

For its part, SCE argues that the relative risk reduction between one mile and the next is not dispositive. Rather, the question is how much absolute risk should be driven down.[442] SCE states that the:

> 400 circuit miles that would remain unmitigated if the Commission adopts Cal Advocates' proposal is the approximate equivalent of not performing any of SCE's proposed mitigation work in 2028. This scope is estimated to account for 5 percent of the risk and 2.2 minutes of SAIDI which equates to over 11.5 million customer minutes of interruption. If affordability and resource constraints could be removed, SCE would prefer to mitigate significantly more risk across this GRC cycle. SCE's proposal strikes the appropriate balance between risk reduction, affordability, and resource availability. SCE's request to cover 1,680 miles across this GRC cycle equates to less than 6 percent of SCE's OCP inventory, while reducing nearly 30 percent of the risk.[443]

Cal Advocates rebuts SCE's risk reduction analysis. Cal Advocates argues that reducing serious OCP events by 29 percent would result in 4.1 serious events per year, a reduction of 1.7 from the current 5.8 level.[444] Cal Advocates asserts that reducing serious OCP events by 24 percent results in 4.4 serious events, a reduction of 1.4 from the current 5.8 level. Cal Advocates reasons that its proposal strikes the balance between risk reduction and rate affordability. Cal Advocates argues that the minimal percentage difference under its proposal versus SCE's proposal results in a decreased risk of SCE customers being unable

[442] Ex. SCE-13, Vol. 1 at 12.

[443] Ex. SCE-13, Vol. 1 at 12.

[444] Cal Advocates OB at 39.

to pay their utility bills and would have a decreased risk of needing to reduce essential electric usage.[445]

Given the parties' positions, we authorize and adopt a 2023-2025 capital forecast of $330.397 million for the OCP, which is a $136.072 million reduction compared to SCE's request: $70.796 million (recorded) in 2023, $55.129 million in 2024, and $204.472 million in 2025. This results in a unit cost of $663,000 per circuit mile for the OCP from 2025-2028.

We also authorize and adopt a mileage scope for the OCP of 1,040 miles from 2025-2028, which is 260 miles annually, with no more than 400 miles total of large-gauge conductor being proactively replaced between 2025-2028. This results in a reduction in mileage scope of 640 miles from 2025-2028 compared to SCE's request, which is a reduction of 160 miles annually. This mileage scope is sufficient for inclusion of all the small-gauge conductor proactive replacement proposed by SCE plus approximately 30 percent of the large-gauge conductor proactive replacement proposed by SCE.

With respect to the AOCP, we authorize and adopt Cal Advocates' recommendation of $5.530 million for 2024, and $5.665 million for 2025. If SCE makes a capital expenditure request in its 2029 test year GRC for the AOCP, SCE shall: (1) base any AOCP forecast on a three-year average of recorded AOCP costs; or (2) the historical number of emergency conductor replacement events and the historical average cost of an emergency conductor replacement event; or (3) the historical average miles of emergency conductor replacement and the historical average cost per mile for emergency conductor replacement. We decline to adopt any future SCE forecasts for emergency conductor replacement

[445] Cal Advocates OB at 40.

in the AOCP that are based on a percentage of the proactive conductor replacement forecast in the OCP.

Additionally, if SCE makes a capital expenditure request in its 2029 test year GRC for the OCP, SCE shall demonstrate in its 2029 GRC application that it: (1) has fully considered alternatives to proactive replacement of entire overhead conductor circuit segments; and (2) show the relative risk reductions and costs of these alternatives compared to proactive replacement of entire overhead conductor circuit segments.

If SCE makes a capital expenditure request in its 2029 test year GRC for the OCP and SCE utilizes its machine learning models to develop any part of the request, SCE shall also make a showing of the following in its 2029 GRC application:

- SCE has undertaken, well prior to its 2029 GRC application, reasonable efforts to improve the transparency and external understanding of its machine learning models in response to concerns raised by Commission Safety Policy Division Staff and Parties (*e.g.*, TURN);
- SCE's machine learning models can accurately identify and weight risk factors; and
- There has been a reasonable amount of independent peer review and verification of SCE's machine learning models.

Finally, if SCE makes a capital expenditure request in its 2029 test year GRC for the OCP and SCE includes proactive replacement of any large-gauge overhead conductor with covered conductor in the request, SCE shall demonstrate the following in its 2029 GRC application:

- Evaluate, by circuit segment, the risk reduction effectiveness achieved by prior OCP activity replacing large-gauge conductors;

- Make a quantitative comparison of the risk reduction achieved from replacing large-gauge conductors and from replacing small-gauge conductors, including the costs of conductor replacement; and
- Demonstrate that SCE has undertaken, well prior to its 2029 GRC application, reasonable efforts to explain in detail how its machine learning models select specific overhead conductor segments for proactive replacement from the universe of eligible overhead conductor segments and that its machine learning models do so accurately relative to identified risk factors.

7.2.6.7. Overhead Switch Replacement Program Discussion

As discussed above, the Overhead Switch Replacement Program is a new program targeting the removal and replacement of 540 technologically obsolete GOAB switches (*i.e.*, group operated switches) and removing 1,000 Idle Installed Switches in 2025-2028. Idle Installed Switches occupy positions on circuits where they no longer serve a useful function and are identified as having no foreseeable future use. SCE has approximately 30,000 distribution GOAB switches, of which approximately 1,350 are obsolete and cannot be adequately maintained and operated due to technological obsolescence, unavailability of replacement parts, and lack of vendor support.[446] The Overhead Switch Replacement Program retires obsolete GOAB switches, gains improved performance ratings and vendor support with present-day GOAB switches, and better manages circuit positions with the current standard GOAB switch's automated ability.

SCE's undisputed 2023-2025 capital forecast for the Overhead Switch Replacement Program is $7.415 million of which $0.600 million was recorded in

[446] Ex. SCE-02, Vol. 1, Pt. 2 at 100.

2023, $0 is anticipated for 2024, and $6.815 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

7.2.6.8. Capacitor Bank Replacement Program Discussion

As discussed above, the Capacitor Bank Replacement program plans to replace or remove 1,236 failed and obsolete distribution capacitor banks in 2025-2028. Targeted capacitor banks are found through the Overhead Detailed Inspection program for overhead capacitors and the Underground Detailed Inspection program and Field Apparatus for padmount capacitor banks in accordance with General Order (GO) 165.

For this TY, the Capacitor Bank Replacement program targets incoming notifications on replacements and removals for capacitor banks and existing notifications from SCE's backlog.[447] Drivers for capacitor bank failures are an excessive number of switch operations, high ambient temperature, and corrosion.[448]

SCE's undisputed 2023-2025 capital forecast for the Capacitor Bank Replacement Program is $23.700 million of which $2.546 million was recorded in 2023, $4.327 million is anticipated for 2024, and $16.827 million is anticipated for 2025.[449] Thus, the program total is $23.700 million. We find these activities and costs reasonable and approve them.

[447] Ex. SCE-02, Vol. 1, Pt. 2 at 111-112.

[448] Ex. SCE-02, Vol. 1, Pt. 2 at 112.

[449] Ex. SCE-02, Vol. 1, Pt. 2 at 129.

7.2.6.9. Automatic Reclosers Replacement Program Discussion

As discussed above, the Automatic Reclosers Replacement Program targets the replacement of 17 oil-filled Distribution Automatic Reclosers and 15 oil-filled Vacuum Fault Interrupters (VFIs) in 2025-2028. This program brings this equipment up to current standards and will decrease the risk of in-service failures and downstream ignitions or outage risks.[450]

SCE's undisputed 2023-2025 capital forecast for the Automatic Reclosers Replacement Program is $2.673 million of which $1.219 million was recorded in 2023, $0 is anticipated for 2024, and $1.454 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

7.2.6.10. 4-kV Remediation Program Discussion

Again, the Commission has two questions presented before it regarding the 4-kV Remediation Program. The first question is whether the Commission should adopt and authorize this program; and the second question is, if the Commission does authorize and adopt this program, what the authorized funding should be.

The 4-kV Remediation Program is designed to address aged and obsolete distribution and substation equipment that are in poor health, as well as outdated system designs that have limited system load capacity and impede operational flexibility with system reliability impacts. No party opposed the activities of the 4-kV Remediation Program. We find that the 4-kV Remediation Program is reasonable. Therefore, we authorize and adopt the 4-kV Remediation Program.

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[450] Ex. SCE-02, Vol. 1, Pt. 2 at 119.

The next question Is how much funding should be approved to support the activities of the 4-kV Remediation Program. We begin this analysis with context. Illustratively, SCE's 4.8-kV, 4.16-kV, and 2.4-kV distribution substations and circuits are collectively referred to as the 4-kV system. SCE began installing 4-kV systems in the 1940s when electric loads were markedly lower compared to today.[451] SCE's current standards for distribution circuits primary voltage are 12-kV and 16-kV.[452] SCE initiated its 4-kV remediation program more than a decade ago. However, of SCE's roughly 800 distribution substations and 4,600 distribution circuits, over 150 4-kV substations and 700 4-kV circuits are still in service and require remediation.[453]

Operating aging and obsolete 4-kV systems presents several operational and functional challenges. This includes capacity limitations, inability to meet increasing customer load demand, lack of operational flexibility, and outdated designs. These challenges restrict infrastructure upgrades and maintenance activities. 4-kV remediations consider the various risk factors, including capacity needs as well as historical performance and design factors associated with each 4-kV system to determine the appropriate system remediation. The remediations can range from partial cutover of a circuit to substation rebuilds.[454]

Given this context, we turn to Cal Advocates' rebuttal position to SCE's 4-kV Remediation Program cost forecasts. Cal Advocates recommends a downward adjustment to the authorized funding for the 4-kV Remediation

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[451] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

[452] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

[453] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

[454] Ex. SCE-02, Vol. 1, Pt. 2 at 131.

Program. Cal Advocates recommends using 2023, the lowest year of SCE's 4-kV load growth forecast, as the basis for its 2024-2025 load growth portion of the 4-kV Remediation recommendation.[455] As a result, Cal Advocates' forecasts for the 4-kV Remediation Program are: $42.605 million in 2023, $43.144 million in 2024, and $122.331 million in 2025.[456]

In support of its position, Cal Advocates opposes the use of the load growth trend presented by SCE which relies on the impact of increased transportation electrification. Cal Advocates argues that this cost category represents work that is separated from and outside of the prioritized scope of the 38 4-kV Remediation Program systems across this GRC cycle.[457] Essentially, Cal Advocates supports the 38 long-term 4-kV remediation projects planned years in advance but opposes the load growth remediations.[458] Cal Advocates argues that the 4-kV load growth remediations have experienced the same degree of postponements as have the other types of 4-kV remediations.

For its part, SCE argues that Cal Advocates' recommendation to use the lowest recent historical value fails to acknowledge the load growth trend presented by SCE that demonstrates that transportation electrification load is growing because of, in large part, state policies.[459] SCE continues to argue that its 4-kV systems are inherently limited in their capacity to serve customers, given that they were installed between 60-80 years ago with drastically different

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[455] Ex. CA-03 at 31-32.

[456] Cal Advocates OB at 43.

[457] Cal Advocates OB at 43.

[458] Cal Advocates OB at 47-48.

[459] SCE OB at 36.

customer and grid needs in mind.[460] SCE asserts that these limitations exist on every 4-kV circuit on SCE's system, and continue to result in delays for customers served by 4-kV circuits, restricting these customers' ability to fully participate in the equitable transition to a decarbonized economy.[461]

While we are cognizant that SCE's 4-kV systems are limited in their capacity to serve customers, we need to account for the downward Load Growth adjustments made in this Proposed Decision, as well as being. We find that Cal Advocates' forecast strikes the appropriate balance between addressing emergent customer and system load growth capacity needs against rate affordability. Therefore, we adopt and authorize the recorded capital expenditures of $90.448 million in 2023, and Cal Advocates' forecasts of $43.144 million in 2024 and $122.331 million in 2025. These forecasts are the same as SCE's forecast for 2023, but are $6.524 million lower for 2024, and $5.047 million lower for 2025.

7.2.6.11. PCB Transformer Removal Program Discussion

As discussed above, the PCB Transformer Removal Program plans to replace approximately 440 distribution line transformers suspected of being contaminated with PCB oil greater than 50 ppm. PCBs have dangerous effects on human health and the environment. The EPA encourages all utilities to remove transformers containing significant levels of PCB.

SCE's undisputed 2023-2025 capital forecast is $5.964 million for the PCB Transformer Removal Program of which $2.080 million has been recorded in

[460] SCE OB at 37.

[461] SCE OB at 37.

2023, $1.914 million is anticipated for 2024, and $1.970 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

7.2.6.12. WPC Program Discussion

As discussed above, the WPC Program targets circuits with the poorest historical reliability. The WPC Program evaluates all outages on a defined WPC to determine the best mitigations to improve reliability for customers experiencing service interruptions. Underground equipment failure was the leading contributor in 2021 for WPCs.[462] Aging cable is also one of the main drivers for underground equipment failure. SCE expects to remediate approximately 71 circuits annually beginning in 2025.[463]

SCE's undisputed 2023-2025 capital forecast for the WPC Program is $49.364 million, of which $0 million has been recorded in 2023, $16.928 million is anticipated for 2024, and $32.436 million is anticipated for 2025. We find these activities and costs reasonable and approve them.

7.2.6.13. CAVA Distribution Infrastructure Replacement Program Discussion

As discussed above, the CAVA Distribution Infrastructure Replacement program will target areas where infrastructure is particularly susceptible to the effects of climate change. CAVA Distribution Infrastructure Replacement projects will be in identified areas where infrastructure is expected to experience increasing heat- and flooding-related events. Both increased heat and/or flood adversely impact distribution infrastructure in ways that can cause outages.

SCE's undisputed 2023-2025 capital forecast for CAVA Distribution Infrastructure Replacement Program is $2.080 million, of which $0 million has

[462] Ex. SCE-02, Vol. 1, Pt. 2 at 126.

[463] Ex. SCE-02, Vol. 1, Pt. 2 at 127.

been recorded in 2023, $0 million is anticipated for 2024, and $2.080 million is anticipated for 2025. We find these activities and costs reasonable and approve them. Now, we turn to the DIM Program.

7.3. DIM Program Overview and Capital-Related Forecasts

The DIM Program activities focus on SCE's distribution lines and equipment located outside of substations. The DIM Program maintenance work includes both expense repairs and capital replacements performed on the distribution grid. The most common types of distribution electrical equipment include transformers, switches, cable, and conductor which typically operate at line voltages of 4-kV, 12-kV, 16-kV, and less frequently at 33-kV. Furthermore, SCE's DIM Program addresses regulatory and internal requirements, and prioritizes work based on the condition of each facility or piece of equipment and its potential safety and reliability impacts.[464] The DIM Program also considers various factors, including the voltage, location, accessibility, and the climate in which the equipment operates.[465]

For the TY, SCE requests:

- $0.202 billion in O&M expenses for test year 2025 to address the DIM Program;[466] and
- $4.492 billion of capital expenditures for years 2023 (recorded) and 2024-2028 (forecast) to address the DIM Program.[467]

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[464] Ex. SCE-02, Vol. 2 at 4.

[465] Ex. SCE-02, Vol. 2 at 8.

[466] Ex. SCE-02, Vol. 2 at 1.

[467] Ex. SCE-02, Vol. 2 at 1. *See also* Ex. SCE-11 at B-1.

The capital expenditure forecast for DIM is approximately 17 percent of SCE's total forecast for distribution grid capital expenditures for 2023-2028.[468] The O&M expense forecast for DIM is approximately 16 percent of SCE's total forecast for distribution grid O&M expenses for 2025.[469]

7.3.1. Distribution Ground Inspections

GO 165 requires inspections of the overhead distribution system, which includes annual grid patrols and distribution ground inspections. GO 165 also requires detailed inspections of overhead distribution equipment every five years. SCE testifies that during the five-year cycle, for any year when SCE does not perform the distribution ground inspection, a grid patrol is performed. These activities include costs for inspecting SCE's overhead distribution electrical system.[470]

The Distribution Ground Inspections Program performs a close-proximity, in-depth evaluation of SCE's overhead electrical facilities. This includes poles, capacitor switches, transformers, guy wires, and risers. This up-close evaluation: (1) identifies hazardous conditions or non-conformances with GO 95 as well as conditions that could potentially result in system failure if left as-is (examples include leaking transformers, broken or damaged equipment, encroachment of line clearances, deteriorated cross arms, and missing or damaged high voltage signs); (2) determines what corrective action is required and prioritizes follow-up corrective action; (3) performs minor repairs at the location; (4) performs a comprehensive risk and data collection inspection utilizing the risk-informed

[468] Ex. SCE-02, Vol. 2 at 3.

[469] Ex. SCE-02, Vol. 2 at 2.

[470] Ex. SCE-02, Vol. 2 at 9.

survey; (5) documents inspection findings, including pending and completed repairs; and (6) validates equipment records and identifies corrections as needed.[471]

SCE states that in 2020, non-labor charges increased from $2 million to almost $10 million. SCE states that the main driver for this increase was due to a change to how Distribution Ground Inspections would be conducted. SCE adopted Inspect App to complete inspections and answer survey questions; this required purchasing of technology equipment to support the enhanced process.[472]

SCE's TY forecast for the Distribution Ground Inspection Program is $12.611 million.[473] The forecast is based on 2022 recorded costs. This forecast has a $0.090 million increase, or a 0.7 percent increase, from the 2022 recorded costs of $12.521 million to reflect certain changes made to SCE's employee compensation program.[474]

7.3.2. Underground Detail Inspections

The Underground Detail Inspections Program includes inspecting SCE's underground distribution electrical system in accordance with GO 165 and SCE's DIM Program. The Underground Detail Inspections Program provides close-proximity examination of underground and pad-mounted distribution equipment. Inspectors assess subsurface and pad-mounted equipment including structures, switches, transformers, visible cables, and associated components to

[471] Ex. SCE-02, Vol. 2 at 10.

[472] Ex. SCE-02, Vol. 2 at 12.

[473] Ex. SCE-02, Vol. 2 at 12.

[474] Ex. SCE-02, Vol. 2 at 12.

identify safety hazards and non-conformances with GO 128. Vault and manhole structures containing only cables are also inspected.[475]

SCE's TY forecast for the Underground Detail Inspections Program is $7.969 million. SCE's Underground Detail Inspections forecast is uncontested.

7.3.3. Distribution Preventive and Breakdown Maintenance (O&M)

Distribution Preventive and Breakdown Maintenance includes the project scope and costs needed for SCE to make repairs to its distribution equipment. SCE states that this activity is necessary for it to provide reliable service to customers and to provide public safety by ensuring that equipment is safe and well maintained.[476] Distribution maintenance is performed on either a planned basis or an unplanned basis and includes both Capital and O&M replacements and repairs. Planned maintenance work is comprised of repairs to SCE's equipment and structures recorded as high priority items. Unplanned activities include repairing SCE equipment and structures that are damaged, compromised, or have failed in service. SCE's TY forecast for the Distribution Preventive and Breakdown Maintenance Program is $112.585 million.[477] The Distribution Preventative and Breakdown Maintenance forecast is uncontested.

7.3.4. Distribution Preventive and Breakdown Maintenance (Capital)

The Distribution Preventative and Breakdown Capital Maintenance Program includes costs to replace distribution equipment. The scope of this work includes removing idle facilities. Idle facilities are facilities that have not

[475] Ex. SCE-02, Vol. 2 at 13.

[476] Ex. SCE-02, Vol. 2 at 17.

[477] Ex. SCE-02, Vol. 2 at 18.

been in use for more than 90 days. Energized, idle facilities pose a potential risk to the public.[478] SCE's removal of an idle facility is driven by two factors: (1) a customer makes a request, including but not limited to a turn-off, removal or relocation upgrade of SCE facilities; and (2) energized idle but not-in-service SCE facilities that are found in the field during the course of business or upon notification.[479]

For 2023-2025, SCE forecasts $1,213.866 million in capital expenditures: $431.070 million recorded in 2023, $378.894 million in 2024, and $403.901 million in 2025.[480] The Distribution Preventive and Breakdown Maintenance Program (Capital) is uncontested.

7.3.5. Patrolling and Locating Trouble

The Patrolling and Locating Trouble Program is performed by SCE's trouble men who act as first responders. The trouble men provide around-the-clock coverage for electrical-service problems resulting from a wide range of events on the distribution system. SCE states that the trouble men respond to emergency situations, customers, outages, partial lights, damaged equipment, and voltage fluctuation issues.[481]

For the TY, SCE forecasts $31.240 million for the Patrolling and Locating Trouble Program. The Patrolling and Locating Trouble Program is undisputed.

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[478] Ex. SCE-02, Vol. 2 at 21.

[479] Ex. SCE-02, Vol. 2 at 21.

[480] Ex. SCE-13, Vol. 2E at 5; Ex. SCE-11E4 at B-1.

[481] Ex. SCE-02, Vol. 2 at 25.

7.3.6. Distribution Apparatus Inspection and Maintenance

The Distribution Apparatus Inspection and Maintenance Program includes the costs associated with inspecting, testing, and maintaining overhead and underground distribution apparatus used for remote monitoring and control. SCE states that some examples of distribution apparatus include capacitors, regulators, network protectors, fault interrupters, and automatic re-closing switches used for line protection and sectionalizing.[482] Both the inspection and resulting maintenance performed by the apparatus crews are included in this activity. SCE also states that apparatus crews with specialized training in automated equipment perform these inspections, including technical diagnostic testing to ensure proper functioning of the equipment. SCE testifies that the Apparatus Inspection and Maintenance Program is designed to support SCE's commitment to providing a safe and reliable electrical distribution system by maintaining proper capability, condition, and operation of the apparatus equipment.[483]

For the TY, SCE forecasts $6.155 million for the Apparatus Inspection and Maintenance Program. The Apparatus Inspection and Maintenance Program is uncontested.

7.3.7. Distribution Claim

The Distribution Claim includes the costs incurred by SCE to repair damage to the distribution system caused by a third party. SCE states that in cases where SCE is able to identify the party responsible for the damage, SCE pursues recovery of the costs to repair the damage. Furthermore, SCE states that

[482] Ex. SCE-02, Vol. 2 at 28.

[483] Ex. SCE-02, Vol. 2 at 28.

the most common cause of damage to SCE's system occurs when a vehicle collides with a distribution pole or other above-ground equipment.[484] The resulting damage is most often downed wires, poles, and pole-mounted equipment, and damage to ground-level transformers and equipment.[485]

For 2023-2028, SCE forecasts $334.672 million for the Distribution Claim Program. The Distribution Claim Program is uncontested.

7.3.8. Streetlight Operations, Inspections, and Maintenance

The Streetlight Operations, Inspections, and Maintenance Program includes all operation and maintenance expenses for SCE's streetlight system. The specific work and activities for this program include operations, inspections, and maintenance related to: (1) billing, mapping, and records maintenance for all streetlights taking service under all SCE streetlight tariffs; (2) inspections; and (3) costs to replace burned-out bulbs, failed photocells or sensors, and other repairs to streetlights.[486]

For the TY, SCE forecasts the Streetlight Operations, Inspections, and Maintenance costs to be $5.351 million. The Streetlight Operations, Inspections, and Maintenance costs are undisputed.

7.3.9. Streetlight Maintenance and LED Conversion

SCE owns 500,000 streetlights and maintains the overall infrastructure that serves over 800,000 streetlights in its service territory. SCE states that streetlights are fixtures, typically mounted on concrete, wood, composite, or steel poles to

[484] Ex. SCE-02, Vol. 2 at 30.

[485] Ex. SCE-02, Vol. 2 at 30.

[486] Ex. SCE-02, Vol. 2 at 33.

illuminate highways, roads, parkways, and sidewalks.[487] SCE also states that most streetlights on its system are concrete electroliers with high pressure sodium valve luminaires. However, SCE states that it commenced the light emitting diode (LED) conversion process in 2016 and will continue to increase LED conversions over time. Most streetlight poles have a single luminaire or lamp; occasionally an electrolier may have multiple luminaires or lamps and can be powered through overhead or underground connections. SCE also owns and maintains outdoor lighting installed in public walkways and parking lots.[488]

SCE's forecast streetlight capital expenditures include five main activities: (a) steel pole replacements; (b) luminaire replacements; (c) conversion of high pressure sodium vapor (HPSV) to LED streetlights; (d) Series Streetlights; and (e) minor capital maintenance.[489] SCE's uncontested 2023–2025 forecast for Streetlight Maintenance and LED Conversion is $105.729 million.

7.3.10. Capital-Related Expense and Other Overview

7.3.10.1. O&M Forecast

7.3.10.1.1. Distribution Support Activities

SCE performs several miscellaneous distribution-related activities which record to Distribution Support Activities. Distribution Support Activities include work activities that are necessary to support SCE's construction crews working on the distribution system. These activities include: (1) Information Technology (IT) chargebacks; (2) Field Accounting Organization (FAO) O&M Activities; (3) Electric Asset Data (EAD); (4) Stand-by Time; (5) Underground Civil

[487] Ex. SCE-02, Vol. 2 at 35.

[488] Ex. SCE-02, Vol. 2 at 35.

[489] Ex. SCE-02, Vol. 2 at 36.

Inspection O&M Activities; (6) Real Properties O&M Activities; (7) Equipment Data Maintenance; (8) Informational Meetings; and (9) Reliability Operations Center (ROC). We summarize these activities, and the costs associated with them, below.

IT Chargebacks: These are costs incurred by the Distribution Business Line for various communication equipment and usage charges. SCE testifies that the equipment and usage charges include smart phones, SCE internal landline service, computer and computer access charges, wireless charges, and laptop connectivity charges. SCE states that these charges are "charged back" to the Distribution Business Line by SCE's Information Technology organization. SCE also states that the communication costs are necessary for field and office employees to effectively communicate and access on-line data necessary for performing their daily work.[490]

FAO O&M Activities: The FAO provides accounting support to distribution field crews. SCE states that FAO personnel primarily support capital work order processing, but also spend a portion of their time performing O&M activities, such as time sheet entries on behalf of field crews, ordering and stocking construction supplies and tools, and other administrative duties. SCE also states that the O&M activities performed by FAO personnel are necessary to provide accurate timekeeping for construction personnel and to maintain supply and tool inventories for SCE's field crews.[491]

Electric Asset Data: SCE states that the EAD program enhances SCE's capabilities to monitor the quality of critical electric asset data attributes. SCE

[490] Ex. SCE-02, Vol. 2 at 45.

[491] Ex. SCE-02, Vol. 2 at 45.

states that this helps ensure improved consistency between what is installed in the field and what is stored across SCE's systems of record and systems of engagement.[492]

Stand-By Time: Stand-By Time is labor costs incurred when distribution field crews are held at the end of a workday in anticipation of potential after-hours emergency work. This occurs when SCE anticipates increased resource requirements due to an approaching storm, or when trouble men are responding to emergencies that may require distribution field crews to make repairs or restore service. SCE states that in these circumstances, crews "stand-by" in the service center until work is assigned or it is determined that their response will not be required. SCE also states that holding crews at the end of their shift is more cost-effective than releasing crews to go home and then calling them back for the emergency work.[493]

Underground Civil Inspection O&M Activities: SCE states that underground civil inspectors are responsible for inspecting underground duct installations prior to the installation of electrical cable and equipment. This underground duct is installed by applicants, and then deeded to SCE upon completion. SCE states that underground civil inspectors charge their labor to the capital project when performing inspections. When the underground civil inspectors are reviewing maps, schematics, designs, construction standards, and performing other administrative duties, their labor is charged to expense. SCE states that the Underground Civil Inspection O&M Activities are necessary for SCE to perform the inspection of all civil work installed on the electric system

[492] Ex. SCE-02, Vol. 2 at 45-49.

[493] Ex. SCE-02, Vol. 2 at 49.

prior to energization because this helps ensure that construction meets SCE's design requirements and standards.[494]

Real Properties O&M Activities: SCE states that its Real Properties Organization is responsible for obtaining and maintaining permits, easements, rights-of-way, and purchases of land where SCE places its assets and lines.[495] Real Properties O&M Activities includes the costs to review existing land rights to maintain compliance, and to review requests from external parties to use SCE's land.[496] The costs for Real Properties O&M Activities include document procurement costs, recording fees, and other costs associated with the acquisition and maintenance of land rights.[497]

Informational Meetings: SCE states that it must share information with employees in a timely manner. SCE also states that the majority of employees in its Distribution Organization perform their work outside of an office setting. These field employees do not have ready access to electronic company communication. Thus, SCE states that informational meetings are held on both a periodic and an ad hoc basis to share information with these field employees. The information shared at these periodic and ad hoc basis meetings includes goals, performance, safety updates, and employee concerns or cover information, such as new or updated company policies, procedures, and programs, new or updated governmental regulations, proper use of existing tools, and the introduction of new tools and work methods.[498]

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[494] Ex. SCE-02, Vol. 2 at 49.

[495] Ex. SCE-02, Vol. 2 at 49.

[496] Ex. SCE-02, Vol. 2 at 49-50.

[497] Ex. SCE-02, Vol. 2 at 50.

[498] Ex. SCE-02, Vol. 2 at 50.

ROC: In 2018, SCE formed the ROC to pursue the use of data science and advanced analytics to enhance troubleshooting of the distribution grid and to improve safety, reliability, and customer experience.[499] SCE states that the ROC develops new diagnostics to better understand grid conditions and to support real-time operations using situational awareness, remote diagnostics, and data-driven decision making. SCE also states that the ROC collaborates with substation operations, distribution, and engineering to provide real-time troubleshooting and analytical support. The ROC transitioned from continually supporting stakeholders at all hours, to a day-to-day operation through providing digital coverage by automating and integrating algorithms.[500]

Equipment Data Maintenance: SCE states that the Equipment Data Maintenance support activity involves processing map sales. SCE also states that it receives third-party requests for its Facilities Maps. These maps depict the location of SCE's overhead and underground electrical assets at a planning level of accuracy. When map sales are processed, SCE employees and contractors will charge them to this activity.[501]

Survey: SCE states that the Survey Support activity involves performing miscellaneous survey work that is not related to surveying/construction of major projects. Under normal situations, SCE states that survey work to support projects is charged to capital and captured under the project costs. When survey

[499] Ex. SCE-02, Vol. 2 at 50.

[500] Ex. SCE-02, Vol. 2 at 50.

[501] Ex. SCE-02, Vol. 2 at 51.

work cannot be performed due to inclement weather and other unforeseen circumstances that prevent surveying, surveyors will charge to this activity.[502]

SCE's TY forecast for Distribution Support Activities is $25.623 million. SCE's forecast for Distribution Support activities is disputed by Cal Advocates.

7.3.10.2. Capital Expenditures

7.3.10.2.1. Tools and Work Equipment

The costs in this category include expenses to purchase portable tools and specialized test equipment that are used by distribution personnel when performing work on SCE's distribution grid. SCE states that the tools and specialized test equipment are required for SCE to execute work on the grid in the safest, most reliable, and most efficient manner possible.[503]

SCE's 2023-2025 capital expenditure forecast for Tools and Work Equipment is $13.377 million.[504] The capital expenditure forecast for Tools and Work Equipment is undisputed.

7.3.10.2.2. Prefabrication

Each of SCE's 34 district service centers has a prefabrication operation that is responsible for staging material for the construction crews, assembling prepackaged kits, and properly disposing of materials removed from jobsites. SCE states that prefabrication activities provide distribution crews with the materials needed for daily construction or maintenance work.[505] Prefabrication creates efficiencies for construction crews and allows SCE to use less expensive

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[502] Ex. SCE-02, Vol. 2 at 51.

[503] Ex. SCE-02, Vol. 2 at 54.

[504] Ex. SCE-02, Vol. 2 at 54; Ex. SCE-13, Vol. 2 at 3.

[505] Ex. SCE-02, Vol. 2 at 57.

resources to manage and stage materials while maintaining the distribution system.[506]

SCE's 2023-2025 capital expenditure forecast for Prefabrication is $72.630 million. The Prefabrication Program is undisputed.

7.3.10.2.3. Distribution Transformers

The programs covered under Distribution Transformers include an array of activities, including: (1) new service connections; (2) distribution preventative and breakdown maintenance; and (3) claims. SCE states that the work performed in many of its distribution capital programs requires the installation or replacement of transformers. SCE also states that transformer purchases support an inventory which allows SCE to maintain the necessary equipment available on hand to perform construction work and to replace failed or deteriorated transformers.[507]

SCE forecasts the following Distribution Transformers capital expenditures for 2023–2025: (1) $188.214 million recorded in 2023; (2) $206.847 million for 2024; and (3) $243.636 million for 2025. These expenditures are disputed.

7.3.11. Safety and Reliability Investment Incentive Mechanism

In its testimony, SCE presents the Safety and Reliability Investment Incentive Mechanism (SRIIM) as a Commission adopted mechanism to incentivize SCE to spend authorized dollars on programs that support safety and reliability, and to maintain a workforce of field employees to support the safe

[506] Ex. SCE-02, Vol. 2 at 57.

[507] Ex. SCE-02, Vol. 2 at 58.

and reliable operation of the electric grid.[508] The SRIIM has two components: (1) hiring field personnel that directly work on projects and programs related to safety and reliability; and (2) capital investment on projects and programs for safety and reliability.

For its 2025 GRC SRIIM Proposal, SCE recommends that the Commission continue the SRIIM as adopted in the 2021 GRC Track 1 Decision, with no structural changes.[509] For the 2025 GRC, SCE proposes no changes to the workforce and capital investment components of the SRIIM from the 2021 decision.[510]

7.3.11.1. SRIIM Workforce Categories

SCE proposes to maintain the SRIIM workforce classifications adopted by the Commission in the 2021 GRC Track 1 Decision and also proposes to continue the SRIIM headcount mechanism.[511] Specifically, SCE proposes to increase the SRIIM headcount target in this GRC above previously adopted levels in the 2021 GRC and proposed levels in the Track 4 filing.[512] SCE proposes to increase the headcount target to 2,691 workers by the end of 2028. SCE states that this increase is commensurate with the necessary growth required to meet the safety and reliability objectives presented in this GRC.[513]

To reach the headcount target of 2,691, SCE estimates an increase of 69 SRIIM positions per year, on average, net of attrition from 2025-2028. SCE also

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[508] Ex. SCE-02, Vol. 2 at 62; *see also* D.21-08-036 at 57-58.

[509] Ex. SCE-02, Vol. 2 at 63.

[510] Ex. SCE-02, Vol. 2 at 63.

[511] Ex. SCE-02, Vol. 2 at 64.

[512] Ex. SCE-02, Vol. 2 at 65.

[513] Ex. SCE-02, Vol. 2 at 65.

states that if the targeted headcount is not met, SCE proposes to refund customers in the same manner as outlined in the 2021 GRC-authorized SRIIM mechanism. Similar to the adopted 2021 GRC, SCE proposes to continue with the necessary mechanism to adjust the target headcount level by one-half the percentage change in requested-versus-authorized transmission and distribution (T&D) capital in the 2025 GRC.[514]

7.3.11.2. Capital Investment

SCE states that the Commission adopted the SRIIM to foster improvements to reliability through investment in the electric grid. SCE asserts that the Commission subsequently expanded the mechanism to also include safety spending to help encourage SCE to spend authorized amounts for select safety and reliability programs. SCE requests that that the Commission continue the capital investment component of the SRIIM with minor modifications based on changes to some program names.[515] SCE states that the categories should be updated to include UCR and WPC Programs, which were grouped under Worst Circuit Rehabilitation.[516] In its testimony, SCE lists the following programs in the SRIIM Capital Program categories: (1) UCR; (2) WPC; (3) 4-kV Overload Driven Cutovers; (4) Circuit Breaker Replacement; (5) Underground Switch Replacement; (6) OCP; (7) Underground Structure Replacement; (8) 4-kV Substation Elimination; (9) CIC Replacement; and (10) Substation Transformer Replacement.[517]

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[514] Ex. SCE-02, Vol. 2 at 65.

[515] Ex. SCE-02, Vol. 2 at 65.

[516] Ex. SCE-02, Vol. 2 at 65.

[517] Ex. SCE-02, Vol. 2 at 66.

In its testimony, SCE also states that any recorded expenditures authorized in the SRIIM capital categories can be offset by recorded amounts over-authorized in the Commission-authorized High Priority and Wildfire Mitigation Program capital expenditures and capital additions. SCE also states that it recommends adding the Wildfire Targeted Undergrounding Program (TUG) to the list of Wildfire Mitigation Programs as it addresses safety risks. SCE recommends keeping the rest of the mechanism the same for the 2025 through 2028 SRIIM period.[518] SRIIM was contested in part by CUE.

7.3.12. Parties' Positions

7.3.12.1. Cal Advocates

For its part, Cal Advocates contests one of SCE's inspection and maintenance, and capital-related expense programs — the Distribution Transformers Program. SCE's capital forecasts for the Distribution Transformers Program are $150.615 million for 2023, $206.847 million for 2024, and $243.636 million for 2025. Cal Advocates recommends the Commission adjust SCE's forecasts downward, to: (1) $111.152 million for 2023; (2) $165.735 million for 2024; and (3) $201.344 million for 2025.[519] When compared with SCE's forecasts, Cal Advocates' forecasts are $39.463 million less than SCE's for 2023, $41.112 million less for 2024, and $42.292 million less for 2025.[520]

Cal Advocates opposes SCE's calculations that led toward the development of its distribution transformer forecast. Specifically, Cal Advocates opposes the way certain variables are calculated within SCE's data models. On

[518] Ex. SCE-02, Vol. 2 at 67.

[519] Ex. CA-03 at 36-37.

[520] Cal Advocates OB at 49.

this basis, Cal Advocates makes downward adjustments to SCE's distribution transformer forecasts. Cal Advocates argues that a 15 percent adjustment to reduce the capital expenditures associated with the distribution transformers growth is reasonable because precise adopted costs are unknown.[521]

Cal Advocates opposes how SCE calculates its float of 15 percent.[522] According to SCE, its data model has a target stock level that is used to designate the quantity of transformers needed each year.[523] The float of 15 percent is applied within the target stock level.[524] Cal Advocates suggests there are two options to calculate the float percentage, including: Option 1 is simply to increase the quantity of required transformers by the float percentage; and Option 2 is to set a certain "Total Stock Level" so that if that level is reduced by the float percentage, the resulting transformer amount will equal the calculated transformer quantity that SCE has determined it needs.[525] Cal Advocates asserts that SCE chose Option 2 and, in its judgment, SCE overstates the needed level of SCE's calculated float which impacts its distribution transformer costs. Thus, Cal Advocates recommends adopting Option 1. Cal Advocates states:

> There is an important difference between the two options. For example, suppose SCE determines that it needs 100 transformers, and that it also needs a 15 percent float buffer. With Option 1, one would take the 100 transformers, and then increase that figure by 15 percent — resulting in a total of 115 transformers for the "Target Stock Level" figure.

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[521] Cal Advocates OB at 51.

[522] Float refers to the buffer between SCE's expected distribution transformer usage and its total inventory. (Ex. CA-03 at 42-43).

[523] Ex. SCE-13, Vol. 2 at 8-9.

[524] Cal Advocates OB at 54.

[525] Cal Advocates OB at 54.

> Cal Advocates endorses this straightforward and reasonable approach. . . . SCE has elected to use Option 2. Based on the hypothetical example, SCE would say it requires a Target Stock Level of 117.647 transformers (not 115 transformers); SCE would then try to justify this figure by saying that if the total of 117.647 transformers is reduced by 15 percent (about 17.647), the result would be 100 transformers.[526]

Cal Advocates asserts its approach is straightforward and reasonable. Lastly, Cal Advocates takes issue with SCE's indirect cost of 30 percent. SCE includes indirect costs (consisting of such items as waste removal) in its Distribution Transformers forecasts.[527] Cal Advocates states that based on SCE's responses to data requests, historical levels are at 28.6 percent and that the indirect percentage should be adjusted to the total of 28.6 percent as opposed to the 30 percent SCE had included in its forecast.[528]

Next, Cal Advocates downwardly adjusts SCE's forecasts for its distribution inspection and maintenance and capital-related activities, which include SCE's activity in streetlight operations, inspections, and its maintenance program. Specifically, Cal Advocates recommends reduced forecasts for the ROC and Electric Asset Data.

First, Cal Advocates recommends $3.597 million for SCE's Electric Asset Data activity in 2025.[529] This amounts to a $10.791 million reduction from SCE's request of $14.388 million.[530] Cal Advocates states it normalized SCE's $14.388 million forecast over the four-year rate case cycle to account for the lack

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[526] Ex. CA-03 at 42-43.

[527] Ex. SCE-13, Vol. 2 at 9.

[528] Cal Advocates OB at 56.

[529] Cal Advocates OB at 60.

[530] Ex. SCE-13, Vol. 2 at 14.

of supporting data and uncertainties in forecasting this activity. In support of its position, Cal Advocates contends that SCE's testimony and workpapers did not include specific, verifiable line-item detail needed to compare and analyze its Electric Asset Data forecast with the same or similar programs and costs incurred to monitor electric asset data. Cal Advocates recommends that for SCE's next GRC, SCE should be required to provide historical expenses and more specific data on its various asset data quality programs to allow for a detailed analysis and evaluation.[531]

Next, Cal Advocates recommends $2.121 million for SCE's Reliability Operations Center, $1.133 million less than SCE's forecast. Cal Advocates contends that SCE did not identify specifically attrition/vacancy levels that resulted in the decline in its expenses from 2020-2022. Cal Advocates also argues that SCE's testimony, workpapers, and data request responses did not identify any documented and verifiable problems encountered which prevented it from meeting its operational and compliance requirements due to the decline in recorded expenses and attrition/vacancies for 2021 and 2022. Thus, Cal Advocates asserts $2.121 million addresses the declining trend of SCE's expenses and provides sufficient funding for SCE's ROC.[532]

7.3.12.2. CUE

CUE supports continuing the SRIIM through 2028 and recommends that the Commission continue to authorize the SRIIM to align SCE's financial interests with ratepayer interests in safety and reliability.[533] However, CUE

[531] Cal Advocates OB at 60.

[532] Cal Advocates OB at 61.

[533] Ex. CUE-01 at 2.

asserts that SCE's proposed Headcount Target of 2,673 is insufficient because it is disconnected from on-the-ground operational needs.[534]

In support of its position, CUE argues that ongoing issues with excessive overtime, overreliance on contract workers, and high attrition rates all indicate that SCE's SRIIM workforce is inadequate to meet SCE's SRIIM labor need.[535] CUE recommends the Commission: (1) adopt a SRIIM Headcount Target of 2,941 to meaningfully reduce excessive overtime; (2) reject any downward adjustments to the Headcount Target if it authorizes a lower training budget and instead, adopt a training budget tailored to SCE's SRIIM hiring need; (3) eliminate the headcount adjustment mechanism; (4) increase penalties for missing the SRIIM Headcount Target; and (5) require SCE to track and report more precise information on SRIIM labor demand and data related to hiring, training, and attrition than provided in this application.[536]

7.3.12.3. TURN

Finally, TURN offered an array of recommendations for the inspection and maintenance and capital-related expenses. TURN makes two primary recommendations. First, TURN recommends SCE reevaluate and, as appropriate, scale back its deployment of and reliance on Inspect App for routine and compliance-based inspections given the clear underestimation of time and resources needed for Inspect App over traditional inspection methods, especially outside of High Fire Threat Districts.[537]

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[534] CUE OB at 17.

[535] Ex. CUE-01 at 2.

[536] CUE OB at 18-36.

[537] TURN OB at 84.

Second, TURN recommends that the Commission direct SCE in its next GRC showing to analyze and address any trends in preventive or corrective maintenance and the impacts on associated capital replacement activities, broken out by each category of Distribution Infrastructure Replacement activity.[538] TURN asserts that this review should consider, at minimum, any trends in maintenance completion as indicated by "closed notifications."[539]

7.3.12.4. SCE's Rebuttal

7.3.12.4.1. Distribution Transformers

In response to Cal Advocates, SCE argues that the Commission should reject Cal Advocates' arguments regarding the transformer forecast.[540] SCE contends that Cal Advocates' proposed changes to inputs within SCE's data model were incorrect across the board.[541] SCE asserts that Cal Advocates inaccurately calculated SCE's float percentage and underestimated SCE's indirect percentage. SCE states that Cal Advocates' proposal to decrease portfolio growth by 15 percent is arbitrary and unnecessary because SCE said it will true-up the transformers forecast once total relevant portfolio costs are authorized. SCE also states that while Cal Advocates is correct that it has not hit the 30 percent threshold, SCE has always been close to hitting it. For example, SCE testifies that in 2023, it finished at 29.4 percent.[542] Thus, SCE asserts indirect costs of 30 percent to continue to be a reasonable estimate. SCE states that once a final capital forecast is adopted by the Commission, Distribution Transformers

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[538] TURN OB at 85.

[539] TURN OB at 85.

[540] SCE OB at 54.

[541] Ex. SCE-13, Vol. 2 at 11.

[542] Ex. SCE-13, Vol. 2 at 11.

capital expenditures will be adjusted accordingly without further adjustments being necessary in this proceeding.[543]

Next, SCE recommends that the Commission reject Cal Advocates' proposed changes to the ROC and EAD within Distribution Support Activities. For EAD, SCE contends that Cal Advocates misunderstands what it means to normalize a forecast and states that uncertainties exist in the forecast due to SCE not having historical costs.[544] SCE also argues that Cal Advocates appears to acknowledge that SCE utilized certain historical data for unit costs and scope driving the work within EAD.[545] Concerning the ROC, SCE asserts that Cal Advocates ignores the fact that SCE is seeking to fill vacancies and that a five-year average would account for the filled vacancies.[546] SCE states that Cal Advocates further ignores SCE's incremental request for $0.300 million for Google Cloud Platform.[547] For these reasons, SCE recommends the Commission adopt SCE's forecast for the ROC and EAD along with all other support activities.

7.3.12.4.2. SRIIM

In response to CUE's position regarding the SRIIM, SCE requests the Commission adopt SCE's proposal regarding the headcount target, continuing SRIIM as adopted in the 2021 GRC Track 1 Decision, maintaining the headcount adjustment mechanism, not increasing the headcount target penalties, and adding TUG to Wildfire Mitigation Programs.

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[543] Ex. SCE-13, Vol. 2 at 12.

[544] Ex. SCE-13, Vol. 2 at 14.

[545] Ex. SCE-13, Vol. 2 at 14-16.

[546] Ex. SCE-13, Vol. 2 at 16.

[547] Ex. SCE-13, Vol. 2 at 16-17.

SCE argues that the Commission should reject CUE's recommendations on the headcount target because CUE's headcount target is overstated and derived from bad math.[548] Second, SCE argues the Commission should reject changes to the headcount adjustment mechanism because the current mechanism was approved in the 2021 GRC Track 1 Decision and the 2018 GRC Decision, and it aligns necessary staffing needs with work levels to ensure SCE does not have a mismatch between work to complete and resources to perform the work.[549]

Next, SCE argues that the Commission should reject recommendations to exclude TUG from Wildfire Mitigation Programs because doing so would not address safety risks.[550] Finally, SCE argues that the penalty for failing to meet headcount targets should not be changed because these penalties have been agreed upon for the last three rate case cycles.[551] SCE argues that CUE's headcount target proposal is based on incorrect calculations and suggests the Commission ignore years that have already been litigated within SRIIM.[552]

7.3.12.4.3. Inspection App

SCE disagrees with TURN's discussion regarding SCE's DIM Program and on the effectiveness of SCE's use of Inspect App. SCE states TURN simply disagrees with SCE's DIM Program and use of Inspect App but does not make any specific recommendations. SCE states that TURN proposed no steps, outcomes, or solutions as well as no proposed justification for reducing SCE's forecast within SCE's DIM Program activities. SCE argues that TURN

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[548] SCE OB at 58.

[549] SCE OB at 59.

[550] SCE OB at 60.

[551] SCE OB at 59-60.

[552] Ex. SCE-13, Vol. 2 at 25.

misunderstands the inspections that use Inspect App and the benefits of using Inspect App.[553] SCE states that TURN fails to clarify: (1) an actual forecast for SCE's DIM Program activities; (2) how Inspect App should be re-evaluated; and (3) why Inspect App is "overkill" for compliance inspections but justified in HFRA.[554] For these reasons, SCE states the Commission should opt for SCE's forecast for all activities associated with SCE's DIM Program and not accept TURN's unsupported recommendation.[555]

7.3.13. Discussion

7.3.13.1. Distribution Ground Inspections

TURN offered an array of recommendations for the DIM Program inspection and maintenance, and capital-related expenses. TURN has demonstrated that its recommendations are reasonable. Therefore, we direct SCE to reevaluate and, as appropriate, scale back its deployment of and reliance on Inspect App for routine and compliance-based inspections given the clear underestimation of time and resources needed for Inspect App over traditional inspection methods, especially outside of High Fire Threat Districts.[556]

Next, we also direct SCE in its next GRC showing to analyze and address any trends in preventive or corrective maintenance and the impacts on associated capital replacement activities, broken out by each category of Distribution Infrastructure Replacement activity. SCE shall consider, at minimum, any trends in maintenance completion as indicated by "closed

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[553] Ex. SCE-13, Vol. 2 at 27.

[554] Ex. SCE-13, Vol. 2 at 28-29.

[555] Ex. SCE-13, Vol. 2 at 29.

[556] TURN OB at 84.

notifications."[557] We, therefore, adopt these recommendations presented by TURN.

Finally, SCE's forecast for TY 2025 of $12.611 million for Distribution Ground Inspections is uncontested. Therefore, we find this forecast reasonable. We authorize and adopt this forecast.

7.3.13.2. Underground Detail Inspections

As discussed above, Underground Detail Inspections includes inspecting SCE's underground distribution electrical system in accordance with GO 165 and SCE's DIM Program. The Underground Detail Inspections TY forecast is $7.969 million and is uncontested. We find it reasonable and approve these activities and costs.

7.3.13.3. Distribution Preventative and Breakdown Maintenance (O&M)

As discussed above, the Distribution Preventative and Breakdown Maintenance includes the project scope and costs needed for SCE to make repairs to its distribution equipment. SCE states that this activity is necessary for it to provide reliable service to customers and to provide public safety by ensuring that equipment is safe and well maintained.[558] For the TY, SCE's forecast for the Distribution Preventative and Breakdown Maintenance is $112.585 million.[559] The Distribution Preventative and Breakdown Maintenance forecast is uncontested. We find it reasonable and approve these activities and costs.

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[557] TURN OB at 85.

[558] Ex. SCE-02, Vol. 2 at 17.

[559] Ex. SCE-02, Vol. 2 at 18.

7.3.13.4. Distribution Preventive and Breakdown Maintenance (Capital)

As discussed above, the Distribution Preventative and Breakdown Capital Maintenance includes costs to replace distribution equipment. The scope of this work includes removing idle facilities. Energized, idle facilities pose a potential risk to the public.[560] For 2023-2025, SCE forecasts $1,213.866 million in capital expenditures. The Distribution Preventative and Breakdown Maintenance (Capital) forecast is uncontested. We find these activities and costs reasonable and approve them.

7.3.13.5. Patrolling and Locating Trouble

As discussed above, the Patrolling and Locating Trouble Program is performed by SCE's trouble men who act as first responders. The trouble men provide around-the-clock coverage for electrical service problems resulting from a wide range of events on the distribution system.[561] For the TY, SCE forecasts $31.240 million for the Patrolling and Locating Trouble program. The Patrolling and Locating Trouble program is undisputed. We find it reasonable and approve these activities and costs.

7.3.13.6. Distribution Apparatus Inspection and Maintenance

As discussed above, the Distribution Apparatus Inspection and Maintenance Program includes the costs associated with inspecting, testing, and maintaining overhead and underground distribution apparatus used for remote monitoring and control. For the TY, SCE forecasts $6.155 million for the Apparatus Inspection and Maintenance program. The Apparatus Inspection and

[560] Ex. SCE-02, Vol. 2 at 21.

[561] Ex. SCE-02, Vol. 2 at 25.

Maintenance Program is uncontested. We find it reasonable and approve these activities and costs.

7.3.13.7. Streetlight Operations, Inspections, and Maintenance

As discussed above, the Streetlight Operations, Inspections, and Maintenance program includes all operation and maintenance expenses for SCE's streetlight system. For the TY, SCE forecasts the Streetlight Operations, Inspections, and Maintenance costs to be $5.351 million. The Streetlight Operations, Inspections, and Maintenance costs are undisputed. We find them reasonable and approve these activities and costs.

7.3.13.8. Streetlight Maintenance and LED Conversion

As discussed above, SCE's streetlight capital expenditures include five main activities: (a) steel pole replacements; (b) luminaire replacements; (c) conversion of HPSV to LED streetlights; (d) Series Streetlights; and (e) minor capital maintenance.[562] SCE's 2023-2025 forecast for Streetlight Maintenance and LED Conversion is $105.729 million. The Streetlight Maintenance and LED Conversion costs are uncontested. We find them reasonable and approve these activities and costs.

7.3.13.9. Distribution Support Activities

We adopt and authorize all SCE's requested Distribution Support Activities. We decline to adopt Cal Advocates' recommendations to reduce the EAD and the ROC. SCE has demonstrated that the EAD forecast is reasonable. SCE has shown that the EAD activity will assist SCE in transitioning to more quantitative risk analysis, more refined risk-informed decision-making, and

[562] Ex. SCE-02, Vol. 2 at 36.

more risk-prioritized deployment of mitigation efforts through both field and operational work. SCE has also demonstrated that its ROC forecast is reasonable by utilizing a five-year average to account for vacancies within the ROC program and also to account for fluctuations in recorded costs within this sub-activity.[563] Thus, we authorize and adopt SCE's EAD and ROC activities' forecasts.

7.3.13.10. Tools and Work Equipment

As discussed above, the costs included in this category include expenses to purchase portable tools and specialized test equipment that are used by distribution personnel when performing work on SCE's distribution grid. The 2023-2028 capital expenditure forecast for Tools and Work Equipment is $13.337 million.[564] The capital expenditure forecast for Tools and Work Equipment is undisputed. We find these activities and costs reasonable and approve them.

7.3.13.11. Prefabrication

As discussed above, the costs in this category provide distribution crews with the materials needed for daily construction or maintenance work. Prefabrication creates efficiencies for construction crews and allows SCE to use less expensive resources to manage and stage materials while maintaining the distribution system.[565] The 2023-2028 capital expenditures forecast for Prefabrication is $143.637 million. The Prefabrication Program is undisputed. We find it reasonable and approve these activities and costs.

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[563] Ex. SCE-13, Vol. 2 at 135.

[564] Ex. SCE-02, Vol. 2 at 54; Ex. SCE-13, Vol. 2 at 5.

[565] Ex. SCE-02, Vol. 2 at 57.

7.3.13.12. Distribution Transformers

7.3.13.12.1. Adjustment to Transformer Portfolio Growth Discussion

We decline to adopt Cal Advocates' recommendations to adjust the distribution transformer growth forecast, the float percentage, and indirect cost percentage. We find that SCE reasonably calculated its distribution transformer forecast. Thus, we adopt SCE's transformer portfolio growth forecast. We adopt and authorize SCE's $612.181 million in capital expenditures for its distribution transformers from 2023 to 2025, which represents SCE's trued-up forecast.[566]

Next, we adopt and authorize SCE's float percentage of 15 percent because SCE has demonstrated that its calculations for quantifying new distribution transformers are reasonable. In calculating the quantities of new distribution transformers that SCE forecasts, SCE includes additional transformers that it describes as "floats."[567] When developing its transformer forecast, SCE applied an inventory float target of 15 percent as the minimum level sufficient in order to protect against the risk of material shortages. SCE defines an inventory float target of a minimum 15 percent as sufficient in order to protect against the risk of shortages for utilization while balancing cost and material purchase availability pressures.[568] We find that the calculation of the inventory in this manner is reasonable.

Finally, we authorize and adopt SCE's indirect cost percentage of 30 percent. The indirect percentage was based on historical levels, informed by where SCE anticipates levels to be during the future years of the GRC period. In

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[566] Ex. SCE-13, Vol. 1 at 47-48.

[567] Ex. SCE-02, Vol. 2 at 61.

[568] Ex. SCE-13, Vol. 2 at 7.

2023, for example, SCE finished at 29.4 percent. Thus, SCE has demonstrated that 30 percent is a reasonable estimate.[569] We authorize and adopt SCE's distribution transformer growth forecast, the float percentage, and indirect cost percentage.

7.3.13.12.2. SRIIM

We authorize and adopt the continuation of the SRIIM. The SRIIM is a regulatory mechanism that the Commission has previously adopted to incentivize SCE to spend authorized dollars on programs that support safety and reliability, and to maintain a workforce of field employees to support the safe and reliable operation of the electric grid. Thus, The SRIIM promotes increased safety in the electric system, system reliability, and cost-effectiveness.

We decline to adopt SCE's proposed Headcount Target of 2,673 because it is disconnected from on-the-ground operational needs. Instead, we adopt CUE's recommendations to ensure SRIIM operates as intended and therefore, we increase the Headcount Target of 2,941 which will meaningfully reduce excessive overtime. We also authorize and maintain the headcount adjustment mechanism. We decline to adopt increased headcount target penalties. We authorize and adopt TUG in the list of Wildfire Mitigation Programs.

8. Meter Activities

Meter Activities encompass all elements associated with the life span of a customer's meter. SCE states the work done in these activities "is required for the safety and reliability of the meter system, guards against the issues caused by technology obsolescence, allows customers to receive timely billing, makes sure

[569] Ex. SCE-13, Vol. 2 at 11.

that all customers pay their fair share for the electricity they use, and protects against the safety issues caused by energy theft."[570]

SCE forecasts combined TY O&M expenses of $35.156 million and combined 2023–2025 capital expenditures of $152.108 million for Meter Activities.[571]

SCE's TY O&M forecast for Meter Activities is uncontested. Cal Advocates is the only party to contest SCE's capital expenditure forecast, recommending $80.090 million for Meter Engineering capital expenditures (2023–2025) or a $45.210 million reduction to SCE's rebuttal forecast.[572]

8.1. Meter O&M

SCE's O&M Meter Activities include: (1) Meter Engineering, Field Meter Maintenance, and Field Meter Testing; (2) Field Meter Reading; (3) Installations, Removals and Relocations; (4) Customer Installation & Energy Theft; and (5) Meter System Maintenance and Design.

For the 2025 TY, SCE originally requested a total of $45.625 million in O&M expenses for Meter Activities.[573] SCE's O&M forecasts are predominately based on the recorded 2022 amounts plus adjustments.[574] Following service of its direct testimony, SCE identified an accounting correction. As explained by SCE, all meter installations and repairs are performed using O&M cost objects, then, on a quarterly basis, SCE performs an analysis to identify which of these costs are associated with capital work and need to be transferred to capital cost objects.

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[570] Ex. SCE-02, Vol. 3 at 4.

[571] Ex. SCE-13, Vol. 3 at 2.

[572] Ex. CA-04 at 14.

[573] Ex. SCE-13, Vol. 3, Table I-1 at 2

[574] Ex. SCE-02, Vol. 3 at 7-21.

SCE states that in 2023 it became aware that the quarterly transfers from O&M to capital in this area excluded a set of cost objects that should have been assessed for capitalization. Accordingly, in its rebuttal testimony SCE revised its TY forecasts so that they would accurately reflect the reduced level of O&M expected in 2025, along with a corresponding increase to the level of Meter Engineering capital expected in 2025. SCE states it has taken the necessary steps to ensure the quarterly analysis of meter installation and repair costs includes all necessary cost objects going forward.[575]

For the 2025 TY, SCE's revised O&M forecast results in $35.156 million for Meter Activities (*e.g.*, a $10.470 million reduction to SCE's original forecast).[576] SCE's original and revised O&M forecasts for Meter Activities are uncontested. We find reasonable and authorize $35.156 million in combined TY O&M expenses for Meter Activities.

8.2. Meter Capital

For 2023–2025, SCE forecasts $152.108 million in capital expenditures for Meter Activities, including an adjustment to reflect recorded 2023 costs.[577] SCE's capital request for Meter Activities includes: (1) Meter Engineering; (2) Meter System Maintenance Design; and (3) Advanced Metering Infrastructure. Each of these activities is described below.

8.2.1. Meter Engineering

Meter Engineering includes the meters needed to meet forecast customer growth, replace defective or damaged meters outside their warranty period, and

[575] Ex. SCE-13, Vol. 3 at 6-8; SCE OB at 64.

[576] Ex. SCE-13, Vol. 3, Table II-6 at 7.

[577] Ex. SCE-13, Vol. 3 at 2; SCE OB at 64.

address meter technology changes for all of SCE's residential, commercial, industrial, and agricultural customers. SCE's Meter Engineering request is comprised of two main activities: (1) routine meter work; and (2) non-routine meter-related projects. Routine meter work includes the provision of new meters and replacement of damaged meters for customers with demands under 200 kilowatts (kW), as well as the installation and replacement of Real-Time Energy Meters (RTEM) for large commercial and industrial accounts with demands above 200 kW.[578] SCE's original capital forecast of $82.355 million (2023–2025) for routine meter work was based on a three-year average from 2020–2022 plus escalation.

SCE's original capital forecast of $15.026 million (2023–2025) for non-routine meter-related projects was based on forecast unit volumes and unit costs for specific projects, including: (1) replacement of cell relays[579] due to obsolescence and the transition from 3G cellular bandwidth to 4G/LTE cellular bandwidth; (2) replacement of 12,000 RTEM meters due to their reliance of radio technology which will no longer be supported; (3) the Catalina Meter Replacement Program, which includes the replacement of 2,400 legacy electromechanical meters on Catalina Island with over-the-air meters; (4) the Complex Meter Replacement Program, which includes the replacement of 5,000 complex meters currently deployed on commercial accounts that have been identified as a safety risk; and (5) the installation of a Broadband Global Area

[578] Real-Time Energy Meters are used to collect and store fifteen-minute interval-usage data. (Ex. SCE-02, Vol. 3 at 12 and 23).

[579] Cell relays work in conjunction with Smart Meters to collect customer interval data and relay that information back to SCE's Network Manage System. One cell relay can transmit data for up to 500 Smart Meters. (*See* Ex. SCE-02, Vol. 3 at 23).

Network device to transmit customer billing, meter events, and performance data through a satellite signal in remote areas where cellular service is unavailable.[580]

SCE made the following adjustments in rebuttal testimony to its original forecast, resulting in a total 2023–2025 capital forecast of $125.300 million for Meter Engineering activities. SCE's revised forecast includes $109.301 million for routine meter work and $15.999 million for non-routine meter-related projects. The adjustments are as follows: first, SCE's revised forecast includes 2023 recorded expenditures ($56.388 million) in place of SCE's original forecast ($29.247 million), which SCE reduced to $41.607 million due to the accounting correction discussed above.[581] Second, SCE revised its TY forecast so it would accurately reflect the incorporation of the accounting adjustment going forward. To accomplish this, SCE increased its original 2025 Meter Engineering forecast by the 2023 adjustment amount (converted into 2025 nominal dollars).[582]

Cal Advocates' recommendation for Meter Engineering capital expenditures is $26.480 million for 2023, $26.480 million for 2024, and $27.130 million for the 2025 TY. For routine meter work, Cal Advocates developed its recommendation by taking the four-year average for costs from 2019 to 2022. In support of its recommendation, Cal Advocates asserts that SCE's routine costs fluctuated over the five-year period (2018 to 2022); that SCE's 2023–

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[580] Ex. SCE-02, Vol. 3 at 21 and 23-27.

[581] The 2023 recorded amount for routine meter work includes $14.781 million that were transferred from Meter Activities O&M to Meter Engineering capital. To remove the potential for overcollection as a result of this transfer, SCE made a regulatory adjustment based on the 2021 GRC cycle to reduce 2023 Meter Engineering capital for rate base purposes down to $41.607 million. (SCE OB at 65-66.)

[582] Ex. SCE-13, Vol. 3 at 7-8; SCE OB at 65-66.

2025 forecast is inflated through the use of 2022 data, which is the highest recorded data from 2013–2022; and that historical data does not show a consistent cost increase from 2020–2022.[583] For non-routine meter work, Cal Advocates recommends zero funding for three specific projects that were authorized in SCE's 2021 GRC but have experienced delays: (1) RTEM work; (2) the Catalina Meter Replacement Program; and (3) Complex Meter Replacement Program. Cal Advocates observes that SCE was authorized a total of $18.550 million in its 2021 GRC for these three projects and recorded only $0.066 million from 2020–2022. Cal Advocates asserts SCE failed to provide supporting documentation that demonstrates the reasonableness of including these three deferred projects again in its 2025 GRC request.[584]

Concerning the forecast for routine meter work, SCE asserts that Cal Advocates does not account for the higher level of 2023 recorded costs or SCE's O&M-to-capital adjustment, which is expected to increase capital expenditures going forward relative to historical recorded amounts. Further, SCE asserts it is not appropriate to include 2019 in the average used to develop the routine meter work forecast. SCE points to the significant increase in meter replacements that it observed in 2020, relative to the previous five years, and asserts the increased replacement rate will continue into the TY as the meter population continues to age.[585]

Concerning the three contested non-routine meter-related projects, SCE asserts the projects were deferred due to supply chain constraints caused by the

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[583] Ex. CA-04 at 13-16; CA OB at 70-71.

[584] CA-04 at 16-20; CA OB at 71-75.

[585] Ex. SCE-13, Vol. 3 at 8-9; SCE OB at 66-67.

COVID-19 pandemic and the worldwide microchip shortage, both of which were outside of SCE's control. Further, SCE asserts the projects are necessary to support customer safety and reliability, and that it is not typical or necessary to perform a cost-benefit analysis for this type of foundational work.[586]

We find reasonable and adopt Cal Advocates' recommendation to use a four-year average for routine meter work, with certain adjustments discussed below. SCE's argument that the significant increase in meter replacements in 2020 was due to SCE's aging meter population is contradicted by the equivalent decrease in recorded routine meter costs the following year. SCE fails to address or explain why there was a significant decrease in routine meter work costs in 2021. Absent any explanation, and given the consistent, annual fluctuation in costs for this activity, we find it reasonable to utilize a four-year average of costs from 2019–2022. However, we adjust Cal Advocates' forecast recommendation to incorporate 2023 recorded costs as well as SCE's O&M-to-capital accounting transfer discussed above. SCE's proposal to include 2023 recorded costs for this activity as well as its proposed accounting correction are uncontested. Further, the inclusion of these adjustments addresses SCE's more general point that capital expenditures for routine meter activities are expected to be higher than historical costs moving forward. With these adjustments, we authorize $104.427 million in capital expenditures for routine meter work from 2023–2025.[587]

We also authorize SCE's full capital request of $15.999 million for non-routine meter-related projects, but direct SCE to record the costs for

[586] Ex. SCE-02, Vol. 3 at 23-25; Ex. SCE-13, Vol. 3 at 9-12; SCE OB at 67-68.

[587] Includes $38.736 million in 2023, $25.066 million in 2024, and $40.625 million in 2025.

non-routine meter-related projects in a new balancing account along with the requirement that any overcollection (*i.e.*, if costs are less than the authorized amount at the end of the GRC period) be returned to ratepayers. SCE has provided sufficient justification demonstrating why each of these projects are necessary to support customer safety and reliability and, on that basis, we do not find it necessary to require a cost-benefit analysis for this type of foundational work. However, while SCE attributes the decreased 2021–2022 expenditures for this activity to lack of material and significant supply chain issues during COVID, and indicates more normal supply chain circumstances are returning, SCE fails to provide any actual evidence demonstrating when meter supply chain circumstances are expected to return to normal. To protect against further, potential deferral of these projects, SCE is directed to track non-routine meter-related project costs in a new one-way balancing account. SCE shall file a Tier 1 advice letter within 30 days from the issuance date of this decision to establish the new one-way balancing account.

8.2.2. Meter System Maintenance Design

SCE's largest customers with demands in excess of 200 kW typically require more complex metering systems. While SCE's Meter Engineering forecast, above, includes the RTEM meter costs for these customers, the networking, engineering, and infrastructure costs to support these meters are captured under Meter System Maintenance Design. SCE's 2023–2025 capital expenditure forecast for Meter System Maintenance Design totals $2.714 million, which is adjusted to include recorded 2023 expenditures. SCE's forecast utilizes an itemized methodology based on the estimated volume of meter device and packet router units to be replaced each year and the unit costs. The number of units included in SCE's forecast is based on SCE's estimate of how many devices

will be needed each year to: (1) support the infrastructure for the new meters being added to the network; (2) refresh existing network infrastructure; and (3) change network designs as network assets deployed in the field reach end-of-life or fail.

Cal Advocates recommends a 2023–2025 capital forecast of $1.236 million ($0.412 million each year) based on the recorded 2018–2022 average Meter System Maintenance Design costs. Cal Advocates asserts SCE has spent, on average, $0.401 million less than was authorized for Meter System Maintenance Design every year over the last 10 years; that SCE's forecast represents a significant increase relative to the five-year average of recorded total meter service maintenance design costs; that SCE did not provide any documentation to justify the recorded increase and decrease in replacement of devices observed during the 2018–2020 and 2020–2022 periods, respectively; and that SCE presents incomplete and insufficient information to justify its 2023, 2024, and 2025 capital expenditure forecasts.[588]

In response, SCE asserts Cal Advocates' alternative forecast is unreasonable and should be rejected for the following reasons: (1) although the recorded costs for this activity decreased between 2020–2022 due to a lack of materials, significant supply chain issues during COVID, and COVID impacts to business customer activities, SCE asserts more normal supply chain circumstances are returning and SCE reasonably expects to be able to return to normal and required activity levels in the forecast period; (2) because the COVID-19 pandemic and supply chain constraints drove down activity levels and associated costs during the later years of the historical period, SCE asserts it

[588] Ex. CA-04 at 8-13; Cal Advocates OB at 64-69.

is not reasonable to use a historical average to determine an appropriate forecast; (3) SCE asserts it has demonstrated its ability to execute higher levels of work when materials and resources are available, as evidenced by recorded 2020 and 2023 costs; and (4) SCE asserts its forecast volume of 650 new meter devices is adequately supported by the use of vendor suggested meter and pack router asset useful life and SCE's conservative assumptions about how many devices SCE could mitigate each year.[589]

As discussed above, SCE fails to present any actual evidence in this proceeding demonstrating that normal meter supply chain circumstances have returned, or when they are expected to return. Moreover, as argued by Cal Advocates, SCE has underspent its authorized Meter System Maintenance Design budget every year for the last 10 years, including recorded 2013–2020 costs that were independent of any supply chain constraints due to COVID. While it is reasonable for SCE's forecast methodology to begin with the vendor suggested asset useful life, the above findings draw into question how many devices SCE will actually mitigate each year. With that said, no party directly contests SCE's proposal to adjust its forecast for this activity to include recorded 2023 expenditures, or the underlying need for this activity, and we find the incorporation of recorded 2023 expenditures may further reflect more recent supply chain circumstances. With this adjustment, we authorize $1.637 million in 2023–2025 capital expenditures for Meter System Maintenance Design.

8.2.3. Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) provides two-way remote meter reading and remote connect and disconnect capabilities, and consists of several

[589] Ex. SCE-13, Vol. 3 at 12-14; SCE OB at 68-69.

elements, including meters, communications network, data repository, and back-office systems/integration. SCE asserts AMI helps advance its operational capabilities for customer service and grid management by providing automation capabilities (*e.g.*, automated on/off switch), enabling field efficiencies (*e.g.*, automated meter reading), and transforming SCE's distribution network into an intelligent, integrated network-enabled monitoring and control system (*e.g.*, real-time system monitoring). AMI has also enabled the transition to time-of-use rates.[590]

SCE's first generation of AMI, which is known as Edison SmartConnectTM (SmartConnect or AMI 1.0), included extensive testing and full deployment of meters and communications network, and updating associated back-office systems, customer programs and services, and customer service operations. SCE states the current AMI system is nearing the end of its useful life in 2028, and existing AMI 1.0 meters are experiencing technology obsolescence and failing at an increasing rate. Accordingly, SCE proposes to begin proactively replacing its meter fleet and associated infrastructure in this GRC cycle to avoid widespread failure, to continue to provide customers adequate billing services, and to avoid additional operational costs. As part of its replacement effort, referred to as AMI 2.0, SCE proposes to put in place new AMI technology that SCE asserts can provide additional functionalities and associated benefits in areas such as decarbonization, customer choice, grid resiliency and reliability, enhanced analytics, and behind-the-meter distributed energy resources (DER) integration.[591]

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[590] Ex. SCE-02, Vol. 3 at 29 and 31.

[591] Ex. SCE-02, Vol. 3 at 29-34.

For 2024–2027, SCE forecasts $49.035 million in capital expenditures for the base-level planning needed to design, procure, and implement AMI 2.0.[592] SCE's capital forecast utilizes an itemized methodology based on the volume of meters and supporting equipment necessary for testing, historical costs for meter and meter-related equipment, and vendor estimates for prototype testing and hosted software solutions. SCE also forecasts $5.016 million in O&M expenses for pre-deployment activities in 2023 and 2024. SCE is not seeking review and cost recovery for these O&M costs in this GRC; instead, SCE proposes to record the O&M costs in a new memorandum account, referred to as the Advanced Metering Infrastructure 2.0 Memorandum Account (AMIMA), for later reasonableness review. SCE plans to file a standalone application in 2025 containing SCE's proposals for review and recovery of the forecast costs for full AMI 2.0 deployment.[593]

SCE's capital expenditure forecast for AMI is uncontested. We find reasonable and approve SCE's 2024–2027 capital request of $49.035 million for base-level planning to design, test, and provide proof-of-concept demonstration prior to full AMI 2.0 deployment. SCE's request to establish the AMIMA is addressed in Section 39 (GRC-Related Balancing and Memorandum Account Proposals).

[592] Ex. SCE-02, Vol. 3E at 34-35; Ex. SCE-13, Vol. 3 at 1-2; SCE OB at 69.

[593] Ex. SCE-02, Vol. 3 at 34-50; SCE OB at 69 and 445-448.

9. Transmission Grid

9.1. Transmission Grid — Transmission Line Rating Remediation and Transmission Infrastructure Replacement

SCE's transmission system comprises over 13,000 miles of transmission lines that operate at voltage levels of 500 kV, 220 kV, 161 kV, 115 kV, 66 kV, and 55 kV. The California Independent System Operator (CAISO)-controlled facilities, which are under Federal Energy Regulatory Commission (FERC) jurisdiction, include all line positions of 500 kV and 161 kV, most 220 kV lines, and certain 115 kV, 66 kV and 55 kV lines.[594]

SCE states it performs routine and reactive inspections of the transmission grid to maintain a safe and reliable system. Transmission inspection activities include routine annual/proactive patrol inspections of SCE's overhead and underground transmission grid and reactive inspections during/after extreme weather events/emergencies.[595] Transmission maintenance activities include O&M and capital transmission line maintenance, insulator washing, and road and rights-of-way maintenance. In addition, SCE's testimony explains the remediation activities resulting from SCE's transmission line rating study and tower corrosion program. SCE states that all programs are targeted at preventing outages and extending the life of the SCE transmission system.[596]

Additionally, SCE operates and maintains a communications network that includes over 5,000 miles of fiber-optic cable.[597] This network is used to dispatch

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[594] Ex. SCE-02, Vol. 4 at 5.

[595] Ex. SCE-02, Vol. 4 at 5.

[596] Ex. SCE-02, Vol. 4 at 5.

[597] Ex. SCE-02, Vol. 4 at 5.

personnel for the following activities: (1) restoration of electric service; (2) new service activation; (3) support of operations and maintenance of the electric grid; and (4) interaction with customers and vendors. This network also enables communication between relays and other equipment installed to protect electrical equipment, such as power quality monitoring equipment, circuit breakers and substation transformers.[598]

Transmission Line Rating Remediation (TLRR): SCE states it conducted a Light Detection and Ranging (LiDAR) study to identify transmission lines potentially in violation of the Commission's GO 95 during emergency loading conditions. SCE states the study was launched in 2006 and the initial results were provided to the North American Electric Reliability Corporation (NERC) in 2011.[599] SCE states that NERC and the Western Electricity Coordinating Council (WECC) requested that SCE add 115 kV radial data to its LiDAR analysis. The studies of the radial lines were completed and shared with NERC in 2013. Then, as part of the study, SCE completed its initial survey of all its CAISO-controlled 13 transmission lines built before 2005.[600] Based on the results of the survey, SCE prioritized the transmission line discrepancies that require line clearance remediation. In its testimony, SCE states that a discrepancy is any condition found in the field that requires remediation to meet GO 95 requirements during emergency loading conditions. SCE further states that initially, the study

[598] Ex. SCE-02, Vol. 4 at 5-6.

[599] Ex. SCE-02, Vol. 4 at 55.

[600] Ex. SCE-02, Vol. 4 at 55.

prioritized the discrepancies into six levels, to remediate in order of highest priority.[601]

Currently, all discrepancies are evaluated on an entire circuit basis, to allow for a holistic and integrated remediation strategy.[602] Radial line discrepancies increased SCE's total number of discrepancies to 11,783.[603] SCE, NERC, and WECC agreed that the Bulk Electric System (BES) discrepancies are to be remediated by the end of 2025 and all radial system discrepancies by 2030.[604] Each project in the remediation plan is reviewed under GO 131D, which defines the rules relating to the planning and construction of electric facilities. Some projects fall under the exemptions listed in GO 131D Section III.B.1 while others will require full permitting and become licensing projects.[605]

In its testimony, SCE states that, through the fourth quarter of 2022, the TLRR program has remediated 3,048 discrepancies, cleared 1,102 as having no violation by SCE engineering, and had 662 cleared by other programs or projects. According to SCE, this leaves 6,968 of the 11,783 discrepancies in need of remediation.[606] O&M remediation work includes re-tensioning circuits, re-framing towers, and grading the land under a transmission line. Capital remediation work includes replacing towers and poles, raising existing towers

[601] Ex. SCE-02, Vol. 4 at 55.

[602] Ex. SCE-02, Vol. 4 at 55.

[603] Ex. SCE-02, Vol. 4 at 55-56.

[604] Ex. SCE-02, Vol. 4 at 55.

[605] SCE OB at 70.

[606] Ex. SCE-02, Vol. 4 at 55.

and three points of connection, and replacing existing conductors (*i.e.*, reconductoring).[607]

SCE requested a TLRR 2023-2025 forecast of $389.962 million at the Total Company level.[608] SCE proposes the Commission authorize SCE's 2023 recorded capital expenditures in place of SCE's original 2023 forecast.[609] SCE's proposal for its TLRR program includes (but is not limited to) the following projects: Eldorado-Pisgah-Lugo (EPL), Gorman-Kern River (GKR), Control-Silver Peak (CSP), and Ivanpah Control (IC) (collectively Main TLRR Projects).[610]

Transmission Infrastructure Replacement (TIR): As described above, SCE's transmission grid spans over 13,000 miles of transmission lines and includes components such as towers, poles, switches, underground structures, cables, and conductors. SCE states that for an individual component, the probability of failure remains relatively low for a period of time, given constant operational and environmental conditions; but eventually, the component's materials weaken and its probability of failure increases.[611]

According to SCE's testimony, a time-dependent replacement rate curve dictates when and what components need replacement and at what rate.[612] SCE's Ex-SCE 02, Vol. 4, Section IV illustrates this concept and details its business enterprise strategy to refine and optimize its approach to asset management.[613]

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[607] Ex. SCE-02, Vol. 4 at 56.

[608] Ex. SCE-13, Vol. 4 at 5.

[609] SCE OB at 70.

[610] Ex. SCE-13, Vol. 4 at 7.

[611] Ex. SCE-02, Vol. 4 at 69.

[612] Ex. SCE-02, Vol. 4 at 70.

[613] Ex. SCE-02, Vol. 4 at 70-71.

SCE states that the average age of some of SCE's transmission asset types continues to increase.[614] For example, certain of the transmission lines and structures installed in the Metro West region are nearing 100 years of service, without previous major overhauls or rebuilds.[615] SCE also highlights that one of its High-Pressure Fluid-Filled cable systems has been in continuous operation under Los Angeles International Airport since its installation in 1971. SCE states that its transmission inspection and maintenance activities enable these components to be operational throughout their serviceable lives.[616]

SCE states that, like every piece of SCE's transmission grid infrastructure, transmission assets require replacement due to age, environmental factors, and operational conditions to enable the safer and more reliable transmission of electricity. Increased levels of infrastructure replacement are necessary to align with steady state replacement rates in the future and to maintain a safe and reliable transmission system.[617]

To address the maturing components of its assets nearing mortality in its system, SCE proposes to use its TIR program. SCE states that the TIR aligns with its Distribution and Substation infrastructure replacement programs. SCE states that the TIR program will help SCE align with the Commission's directive to evolve risk modeling and risk-informed decision-making to help maintain a safer, more reliable system.[618]

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[614] Ex. SCE-02, Vol. 4 at 70-72.

[615] Ex. SCE-02, Vol. 4 at 69.

[616] Ex. SCE-02, Vol. 4 at 69.

[617] Ex. SCE-02, Vol. 4 at 69.

[618] Ex. SCE-02, Vol. 4 at 70.

SCE states that, starting in 2025, SCE's TIR replacement activities will be identified, prioritized, and driven by an evolving and maturing quantitative risk analysis.[619] In addition to leveraging analytics, SCE states it will continue to employ traditional methods such as field observations and subject matter expertise to address the complex and dynamic needs of the transmission system. By combining transmission grid expertise with advanced analytics, SCE states it can bolster its transmission grid infrastructure replacement strategy to continue to serve customers safely and reliably with clean energy and help meet customers' changing expectations in transmission reliability as the state transitions to a decarbonized economy.[620]

SCE's capital funding request for the 2025-2028 period for the TIR program is $253.858 million, which includes the following components: (1) Transmission Overhead Re-Conductor Program; (2) Transmission Line Rebuild Program; (3) Fault Return Conductor Installation Program; (4) Transmission Switch Replacement Program; (5) Pothead Replacement Program; and (6) Transmission Underground Cable Replacement Program.[621]

9.1.1. Parties' Positions

9.1.1.1. Cal Advocates

Cal Advocates challenges two areas of SCE's forecasts. Cal Advocates challenges SCE's TLRR capital forecast and SCE's TIR program. We discuss Cal Advocates' position on each of these areas of SCE's forecast, below.

[619] Ex. SCE-02, Vol. 4 at 71.

[620] Ex. SCE-02, Vol. 4 at 71.

[621] Ex. SCE-02, Vol. 4 at 71-74.

First, Cal Advocates recommends downward adjustments to SCE's TLRR program capital expenditure requests. Cal Advocates reasons that because of project delays, three of the Main TLRR Projects should have an updated in-service date which leads to a reforecasting of project expenditures. Cal Advocates recommends project in-service updates for the following projects: (1) GKR; (2) CSP; and (3) IC.[622] Cal Advocates states that the delays of these projects make SCE's forecasts inaccurate. Thus, Cal Advocates' proposed updated, in-service dates and downward adjustments would result in the Commission authorizing $6.992 million for 2023, $13.456 million for 2024, and $30.047 million for 2025, for TLRR capital expenditure (Commission-jurisdictional amounts).[623]

Second, Cal Advocates asserts that SCE's requested contingency for the Gorman-Kern River Project is unreasonable.[624] Cal Advocates recommends that the Commission should authorize the total cost estimate for the Gorman-Kern River Project contingency/known risk budget to $17,656,009, which results in a $41,640,791 reduction of SCE's request of $59,296,800.[625] Cal Advocates argues that SCE's request of $59,296,800 is unreasonable for a project as mature and routine as the Gorman-Kern River Project.[626]

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[622] Ex. CA-09 at 11-13.

[623] Cal Advocates presents its recommendation in Commission-jurisdictional amounts instead of Total Company amounts. The Joint Comparison Exhibit indicates that Cal Advocates' forecast is $72.140 million for 2023, $78.779 million for 2024, and $207.072 million for 2025. SCE's forecast is $52.515 million for 2023, $87.332 million for 2024, and $250.115 million for 2025.

[624] Cal Advocates OB at 79.

[625] Cal Advocates OB at 79-80.

[626] Cal Advocates OB at 80.

With respect to the TIR, Cal Advocates recommends downward adjustments to SCE's request. First, Cal Advocates recommends $19.908 million for 2023, $21.577 million for 2024, and $18.339 million for 2025, for TIR capital expenditures (Commission-jurisdictional).[627] In support of its position, Cal Advocates states that SCE's TIR approach results in annual expenditures that are more than triple the average annual expenditures under the current approach. Cal Advocates argues that SCE has not provided a quantitative assessment of the extent to which the new approach will affect safety and reliability.[628] Cal Advocates states that SCE has not demonstrated that the benefits of the change in approach merit the increase in cost. Thus, Cal Advocates recommends that the Commission approve only expenditures consistent with historical levels and that the Commission require SCE to provide a cost-benefit analysis of the proposed change in approach as a prerequisite for approval of the incremental costs.[629]

9.1.1.2. EPUC

For its part, EPUC argues that SCE does not consider affordability impacts in its TLRR request and that these expenditures are not needed.[630] EPUC recommends SCE should prioritize and then complete the TLRR work at a more

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[627] Cal Advocates OB at 81; *see also* Ex. CA-09 at 17-19. Cal Advocates presents its recommendation in Commission-jurisdictional amounts instead of Total Company amounts. The Joint Comparison Exhibit indicates that Cal Advocates' forecast for Transmission Capital Maintenance (the parent activity of the TIR program) is $64.960 million for 2023, $69.996 million for 2024, and $54.863 million for 2025. SCE's forecast is $35.987 million for 2023, $69.996 million for 2024, and $98.193 million for 2025.

[628] Cal Advocates OB at 81.

[629] Ex. CA-09 at 17.

[630] EPUC OB at 27.

reasonable pace so that the work may be completed without unnecessarily burdening SCE customers.[631]

9.1.1.3. SCE's Rebuttal

SCE opposes Cal Advocates' recommendations. First, SCE states that Cal Advocates' recommendation to update the project in-service dates for the GKR, CSP, and IC should be denied.[632] SCE argues that while the project in-service dates may have changed since the GRC forecast was submitted in May 2023, changes in such dates should not be made in the RO Model as Cal Advocates recommends. In support of its position, SCE states that: (1) updating project in-service dates and reforecasting project expenditures based on updated-in service dates would lead to continuous reforecasting throughout the proceeding, which would be unduly burdensome on parties and the Commission, and would contravene orderly processing of SCE's Application; (2) SCE's opening testimony was based on information reasonably available at that point in time; and (3) schedules for projects going through any licensing or agency permitting process are outside of SCE's control and, as such, SCE uses historical information to estimate project timelines for forecasting.[633]

Second, SCE states that the contingency and known risk reserve for the Gorman-Kern River Project should not be reduced. SCE argues that Cal Advocates confuses the total contingency amount for the Gorman-Kern River Project.[634] SCE states that it included both the contingency amount and known risk reserve as one cost object/work breakdown structure in the RO Model and

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[631] EPUC OB at 29.

[632] SCE OB at 70.

[633] SCE OB at 71.

[634] SCE OB at 72; *see also* Ex. CA-09 at 12-13.

SCE's standard capital workpapers.[635] SCE also states that this particular line item includes both a contingency and a known risk reserve, each of which have a separate purpose and a different calculation.

Next, SCE states it included the known risk budget in the same work breakdown structure line item as the contingency budget to isolate the costs related to uncertainty from known project costs.[636] In short, SCE states that its use of a 15 percent contingency is appropriate and the contingency and known risk reserve are reasonable to mitigate risks outside of SCE's control.

Finally, SCE states that its TIR program is reasonable because it is a centralized, risk-informed, and targeted approach to monitoring and, as necessary, replaces aging infrastructure before detrimental in-service failures occur.[637] SCE argues that Cal Advocates' downward adjustments and reliance on historical averages are outdated approaches that would greatly underfund current system needs.[638]

9.1.2. Discussion

As stated above, two areas of SCE's forecasts were challenged by Cal Advocates and EPUC: the TLRR and TIR. However, SCE's Transmission Grid O&M request was uncontested. SCE has demonstrated that the uncontested expenditure requests are reasonable. Therefore, we adopt SCE's uncontested requests. Below, we discuss TLRR and TIR.

TLRR: SCE requested a TLRR 2023-2025 forecast of $389.962 million at the Total Company level and presented a rebuttal proposition request for

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[635] SCE OB at 72; *see also* Ex. SCE-13, Vol. 14, Appendix B, WP SCE-02, Vol. 4 at 112.

[636] SCE OB at 73.

[637] Ex. SCE-02, Vol. 4 at 69-71.

[638] SCE OB at 75.

authorization of its 2023 recorded capital expenditures in place of its original 2023 forecast.[639] We find SCE's proposal for its TLRR program reasonable and adopt its expenditure request. We also decline to adopt Cal Advocates' recommendation to modify the in-service dates of the Four Major TLRR Projects.

First, SCE has demonstrated that the TLRR program is reasonable, and its activity is necessary. The record demonstrates that the TLRR capital forecast is based on a compliance requirement for completion of all BES discrepancies with completion dates by 2025 and 2030. Thus, we decline to adopt Cal Advocates downward adjustments for the 2023, 2024, and 2025 TLRR capital expenditures. We also decline to adopt Cal Advocates' recommendation to update the project in-service dates for three of the Main TLRR Projects.

However, we note that SCE does not dispute that the project in-service dates have changed since their forecast was submitted.[640] While SCE has shown that agency permitting and/or licensing review contributes to project delays, the Commission observes that SCE has primary responsibility for aspects of project management that may also affect permitting timelines and project in-service dates. The Commission directs SCE to proactively collaborate with the permitting and/or licensing agency to help support an efficient review process and an improved forecast of in-service dates during the next GRC cycle.

We are also persuaded by SCE that the contingency and known risk reserve for the Gorman-Kern River Project should not be reduced. SCE's forecast for the Gorman-Kern River Project includes two separate amounts to address risk associated with the project: (1) a contingency; and (2) a known risk reserve.

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[639] SCE OB at 70; *see also* Ex. SCE-13, Vol. 4 at 5.

[640] SCE OB at 70-73.

SCE has shown in its testimony and workpapers that the contingency and known risk reserve have separate purposes and different calculations.[641] Thus, SCE's use of a 15 percent contingency and known risk reserve is reasonable.

A contingency is intended to cover uncertainty and variability in the estimated cost of known scope as well as for inadequacies in estimating methods and scope and estimating limitations. Collectively, SCE's known risk reserve captures the costs related to uncertainty from known project costs and general known risks found on major projects which may include:
(1) environmental-related construction delays associated with wildlife; (2) delays associated with outage constraints; (3) geotechnical obstacles; (4) unanticipated discovery of cultural resources; and/or (5) additional property acquisitions or condemnation.[642]

As discussed in the Post-Test Year Ratemaking section of this decision, SCE requests attrition year capital additions via a budget-based post-test year ratemaking forecast for the Gorman-Kern River project. Given the cost of the project and the potential delays discussed above, and for the reasons discussed in Section 42 (Post-Test Year Ratemaking), we decline to adopt this. SCE may request cost recovery of the project once it is completed and placed into service by either: (1) filing a Tier 2 advice letter prior to its next GRC, including a request in its annual Post-Test Year Ratemaking advice letter; or (2) in the next GRC ratebase true-up.

In conclusion, the contingency and known risk reserve are reasonable to mitigate the risks outside of SCE's control.

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[641] Ex. SCE-13, Vol. 4 at 11-13; *see also* Ex. SCE-13, Vol. 4, Appendix B, WP SCE-02 Vol. 4 at 112.

[642] SCE OB at 73.

TIR: The TIR identifies six activities — transmission overhead re-conductor program, transmission line rebuild program, fault return conductor installation program, transmission switch replacement program, pothead replacement program, and transmission underground cable replacement program — that provide SCE with the opportunity to identify equipment and assets that need replacement. SCE requests $11.234 million (recorded) for 2023, $22.630 million for 2024, and $62.549 million for 2025, for TIR capital expenditures. Cal Advocates recommends $19.908 million for 2023, $21.577 million for 2024, and $18.339 million for 2025, for TIR capital expenditures. We decline to adopt Cal Advocates' recommendation because we are persuaded that the TIR approach will increase safety and reliability for SCE customers.

Indeed, SCE has shown that major transmission assets and infrastructure are nearing the end of their useful lives,[643] which requires SCE to use a new, centralized risk-informed approach to monitor and replace, as necessary, aging infrastructure before in-service failures occur. Thus, we decline to adopt Cal Advocates' recommendation to use historical averages because it would not accurately account for current system needs, current system risk and uncertainty, or focus acutely on proactive infrastructure replacement. In conclusion, we adopt SCE's TIR expenditures because SCE has shown the program to mitigate risk and increase safe and reliable service.[644]

[643] Ex. SCE-02, Vol. 4 at 69-71.

[644] Ex. SCE-13, Vol. 4 at 22-25.

10. Substation

10.1. Substation O&M and Capital Expenditures

10.1.1. Contested Programs

10.1.1.1. Grid Monitoring and Operability O&M

10.1.1.1.1. Grid Monitoring and Operability

SCE's transmission, sub-transmission, and distribution grids require constant oversight and control to provide safe, reliable, and continuous electrical service to customers. SCE states that this is accomplished through SCE's Grid Monitoring and Operability programs. Grid Monitoring & Operability's O&M forecast is comprised of two sub-activities: (1) Monitoring and Operating Substations; and (2) Monitoring Bulk Power Systems. Each activity has its own supporting forecast methodology.[645]

10.1.1.1.2. O&M Expenses: Monitoring and Operating Substations

The day-to-day operations of the non-bulk power system (transmission, sub-transmission, and distribution system) are performed by switching centers geographically dispersed throughout the SCE service area.

The switching centers are staffed by SCE personnel. The operation of these switching centers relies primarily on two types of employees: (1) system operators; and (2) substation operators. System operators are stationed within the switching centers and are responsible for remotely monitoring and operating the portion of the transmission, sub-transmission, and distribution system within their geographic control area. Substation operators perform routine switching to support planned work that requires an outage and emergency switching to respond to any unplanned events that affect the grid. Routine switching

[645] Ex. SCE-13, Vol. 5 at 7-19.

involves de-energizing and isolating equipment that requires maintenance or capital work.[646]

For the above activities, SCE forecasts $54.450 million for TY 2025 expenses (Labor and Non-Labor). In developing this forecast, SCE states that it started with its 2022 recorded expenses. SCE states it then made the following adjustments to this amount: (1) an increase of $7.463 million to accommodate its need for additional resources for the T&D Capital and O&M Portfolio; (2) an increase of $1.242 million to reflect changes in SCE's employee compensation program; and (3) a decrease of $0.666 million attributable to employee-led efficiency savings related to reducing the number of required resources through increasing efficiencies in this activity.[647] Cal Advocates contests SCE's forecast for this program.

10.1.1.1.3. O&M Expenses: Monitoring Bulk Power Systems

The Bulk Power System consists of equipment under CAISO control, which includes transmission and lower voltages. The Monitoring Bulk Power System activity is supported by two groups of personnel: (1) System Operators in the Grid Control Center (GCC); and (2) Grid Network Solutions.[648]

SCE testifies that the GCC is responsible for the overall monitoring and control of SCE's transmission system.[649] SCE states that the GCC acts as the

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[646] Ex. SCE-13, Vol. 5 at 8.

[647] Ex. SCE-13, Vol. 5 at 8.

[648] Ex. SCE-13, Vol. 5 at 8.

[649] Ex. SCE-13, Vol. 5 at 11. The GCC staff is composed of 60 employees, including power system operators, operating engineers, and managers. GCC activities can be categorized into three main responsibilities: (1) monitoring and operating SCE's bulk power system; (2) coordinating planned outages; and (3) developing and maintaining operating procedures.

primary point of contact for CAISO and has the authority and obligation to direct SCE's transmission grid operations during normal and emergent conditions. SCE states that these activities are critical for maintaining system reliability and meeting regulatory compliance requirements.[650]

Next, SCE testifies that the Grid Network Solutions team is responsible for operating, repairing, and maintaining network communication infrastructure and the Supervisory Control and Data Acquisition systems. SCE testifies that this allows the GCC to monitor and control SCE's bulk power system. The Grid Network Solutions team is composed of two primary divisions: (1) Power System Controls; and (2) Grid and Telecom (Engineering, Construction, and Operations).[651]

SCE forecasts $86.062 million in expenditures for the Bulk Power Systems activities.[652] SCE states that it utilized its 2022 costs as the starting basis for its forecast.[653] SCE states it then added $1.943 million in costs associated with hiring additional resources due to forecast labor growth based on the T&D Capital and O&M portfolio and made an additional adjustment to reflect certain changes in SCE's employee compensation program.[654] Cal Advocates contests SCE's forecast.

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[650] Ex. SCE-13, Vol. 5 at 11.

[651] Ex. SCE-13, Vol. 5 at 11.

[652] Ex. SCE-13, Vol. 5 at 13.

[653] Ex. SCE-13, Vol. 5 at 11.

[654] Ex. SCE-13, Vol. 5 at 20.

10.1.1.2. Inspections and Maintenance

10.1.1.2.1. O&M Expenses: Relay Inspections and Maintenance

A protective relay's main function is to monitor, detect, and quickly act to eliminate abnormal power system events such as faults. SCE states that a failure of a protection system to operate when needed can have many undesirable outcomes such as increasing safety hazard exposure to its employees and the public, environmental damage such as oil spills and fire, costly power equipment damage, or a widespread power outage.[655] Further, due to the critical function protective relays perform, SCE states that conducting periodic inspections and maintenance is critical to maintaining a safe and reliable electric grid.[656]

SCE testifies that the purpose of its Relay Inspections and Maintenance program is to ensure proper performance, functionality, and availability of the protection systems. Depending on the type of relay, the inspection activity may be comprised of a visual inspection, testing and calibration using specialized equipment, verification of current and voltage signals from source devices, function testing, and control and trip circuitry integrity testing.[657] SCE states that based on the results of these inspections, protection system components might need to be repaired or replaced.

For the above activities, SCE forecasts 2025 Test Year expenses at $3.217 million.[658] SCE states that it used a five-year historical average of 2018 to 2022 recorded expenses plus an adjustment. SCE states that costs for

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[655] Ex. SCE-13, Vol. 5 at 11.

[656] Ex. SCE-13, Vol. 5 at 20.

[657] Ex. SCE-13, Vol. 5 at 20.

[658] Ex. SCE-13, Vol. 5 at 2.

maintenance can vary based on information gathered during field inspections and the type of repair required. SCE further testifies that year-over-year relay inspection and maintenance costs have significant fluctuations due to off-cycle inspections and various environmental factors.[659] Cal Advocates contests SCE's forecast.

10.1.1.2.2. Other Substation Equipment Inspections and Maintenance

Substations contain a wide variety of equipment. A significant proportion of this equipment is directly involved with the primary purpose of the substation: controlling the movement of electrical energy. SCE states that to ensure that this equipment continues to operate efficiently, other miscellaneous systems are required to support their operation. SCE contends that these systems support the operation of substation switching equipment as well as the many non-switching activities that occur in a substation. SCE states that some substation equipment receives scheduled maintenance consisting of testing, lubrication and/or a thorough cleaning while others are visually inspected by crews for corrosion, leakage, and degradation. Detailed inspections and tests are conducted if anomalies are noted during scheduled maintenance.[660] SCE states that the results of the detailed inspections and testing may lead to additional maintenance or replacement of the equipment.[661]

SCE's 2025 Test Year forecast for the above activities is $4.945 million. SCE states that this is based on a three-year average along with an adjustment to

[659] Ex. SCE-13, Vol. 5 at 20.

[660] Ex. SCE-13, Vol. 5 at 22.

[661] Ex. SCE-13, Vol. 5 at 23.

reflect changes made to SCE's employee compensation program for labor, and an itemized forecast for non-labor.[662] Cal Advocates contests SCE's forecast.

10.1.1.3. Substation Capital

10.1.1.3.1. Preventive Maintenance

According to SCE, its Preventive Maintenance programs address broader issues identified by substation engineering, asset management, substation program managers, or field employees that threaten safety, reliability, or cybersecurity.[663]

SCE testifies that some equipment identified for replacement through inspections may not have to be replaced immediately. In such cases, SCE states that this equipment is left in service and monitored until a replacement can be planned. SCE states that this approach reduces costs associated with immediate replacement and forced outages. In other cases, to avoid operational failure, SCE states that it targets replacing substation equipment and ancillary systems that are required for proper Substation operation that are nearing or surpassing the end of service life, have degraded equipment health condition, or have reached obsolescence. SCE states that this programmatic approach covers all Substation equipment, systems, structures and facilities necessary for proper substation operation that are not included in the Substation Infrastructure Replacement Program.[664]

Cal Advocates does not contest SCE's methodology and programmatic approach for the activities associated with the Preventive Maintenance forecast.

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[662] Ex. SCE-13, Vol. 5 at 23.

[663] Ex. SCE-13, Vol. 5 at 24.

[664] Ex. SCE-13, Vol. 5 at 24.

However, Cal Advocates opposes including the costs of the Edison Training Academy. We discuss this further, below.

10.1.1.4. Substation Infrastructure Replacement Readiness and IT Project Support

SCE's Substation Infrastructure Replacement Program (Sub IR) proactively replaces aging, obsolete, and at-risk substation equipment and structures in order to prudently maintain SCE's substation system. SCE states that it leverages programs in its Sub IR portfolio to prudently target and replace assets before in-service failures occur. To do this, SCE testifies that it utilizes data analytics, asset health condition, age, and other factors to address and mitigate risks associated with in-service failures of substation assets, and to remove obsolete equipment.[665]

Sub IR includes four separate programs, two of which were disputed. Cal Advocates and TURN recommend reductions to the Substation Transformer Bank Replacement Program. TURN also challenges SCE's Circuit Breaker Replacement Program. The Substation Rebuild Program and Relays Protection and Control Replacement Program are uncontested. We discuss this further, below.

10.1.1.4.1. Substation Transformer Bank Replacement Program

The Substation Transformer Bank Replacement Program identifies and replaces substation power transformers based on the asset's health condition and risk of in-service failure.[666] Power transformers are critical substation assets used

[665] Ex. SCE-13, Vol. 5 at 26.

[666] Ex. SCE-02, Vol. 5 at 136.

to step up or down electric voltage to transmit power over long distances or distribute power to customers. Power transformers interconnect networks at different voltages; power transformers have a primary voltage (high side) and secondary voltage (low side) in addition to power capacity rating. There are over 2,200 power transformers operating in SCE substations.[667]

According to SCE, power transformers face degradation due to age, environmental, and operational factors that impact their health. Proactive replacement is necessary to avoid the safety and reliability risks associated with asset failures. Replacing existing power transformers is an intensive and complex effort that requires detailed engineering and logistical planning.[668]

10.1.1.4.2. Circuit Breaker Replacement Program

The Circuit Breaker Replacement Program identifies and replaces circuit breakers based on asset health condition and risk of in-service failure. According to SCE, Substation Circuit Breakers protect electric assets by interrupting current generated from short-circuit events. SCE states that these faults have the potential to damage downstream assets or pose public safety risks. SCE testifies that they also isolate abnormal conditions to a portion of the system to prevent cascading outages that impact a larger population of customers. Circuit breakers can de-energize circuits or circuit segments for operational purposes while work is performed.[669]

SCE states that there are over 12,700 circuit breakers operating in its service area. SCE also states that circuit breakers face degradation due to age,

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[667] Ex. SCE-02, Vol. 5 at 137.

[668] Ex. SCE-02, Vol. 5 at 137.

[669] Ex. SCE-02, Vol. 5 at 141.

environmental, and operational factors that impact their operational health. SCE states that proactive replacement is prudent to avoid the safety and reliability risks associated with circuit breaker failures.[670] This program is contested.

10.1.2. Uncontested Programs

10.1.2.1. Substation Rebuild Program

SCE states that the Substation Rebuild Program is designed to comprehensively address substation issues such as structural degradation, switchrack upgrades, equipment in poor condition (*i.e.*, switchgear, transformer, circuit breaker, *etc.*), capacity, capability, and geological (*i.e.*, foundation) issues. SCE states that this program allows SCE to more comprehensively resolve the numerous issues and risks associated with operating an expansive substation footprint.[671] This program is uncontested.

10.1.2.2. Relays Protection and Control Replacement Program

SCE states that the Relays Protection and Control Replacement Program identifies and proactively replaces substation protective relays, controls, automation, monitoring, and event recording equipment. The equipment captured within this program contains: (1) the Relay Replacement Program; (2) Substation Automation (SA) Replacement Program; and (3) Digital Fault Recorder (DFR) Program.[672] This program is uncontested.

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[670] Ex. SCE-02, Vol. 5 at 141.

[671] Ex. SCE-02, Vol. 5 at 146.

[672] Ex. SCE-02, Vol. 5 at 157-172.

10.1.2.3. Circuit Breaker Inspection Maintenance

SCE requests $7.388 million for its Circuit Breaker Inspection and Maintenance program.[673] SCE states its Circuit Breaker Inspection and Maintenance Program is intended to help ensure proper performance and availability of the electrical grid.[674] This program is uncontested.

10.1.2.4. Transformer Inspection and Maintenance

SCE requests $4.423 million for its Circuit Breaker Inspection and Maintenance program.[675] SCE states that the purpose of SCE's power transformer Inspection and Maintenance program is to ensure proper performance and availability for the electrical grid.[676] This program is uncontested.

10.1.2.5. Minor Equipment and Supplies

SCE requests $2.735 million for its Minor Equipment and Supplies program.[677] This program supports non-switching control and operation of a substation.[678] This program is uncontested.

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[673] Ex. SCE-02, Vol. 5 at 70-73.

[674] Ex. SCE-02, Vol. 5 at 71.

[675] Ex. SCE-02, Vol. 5 at 76-78.

[676] Ex. SCE-02, Vol. 5 at 77.

[677] Ex. SCE-02, Vol. 5 at 93.

[678] Ex. SCE-02, Vol. 5 at 87.

10.1.2.6. Equipment Washing

SCE requests $1.634 million for its Equipment Washing program.[679] SCE states that the purpose of this program is to prevent contamination of high-voltage insulators.[680] This program is uncontested.

10.1.2.7. Substation O&M Breakdown Maintenance

SCE requests $2.750 million for its Substation Breakdown Maintenance program.[681] SCE states that the purpose of this program is to cover repairs from breakdown and reactive maintenance on all major and minor equipment types.[682] This program is uncontested.

10.1.2.8. Substation Inspections and Maintenance — Hydro

SCE requests $1.043 million for its Substation Inspections and Maintenance — Hydro program. SCE states that the purpose of this program is to address substation inspection and maintenance activities for SCE's hydroelectric plants.[683] This program is uncontested.

10.1.2.9. Substation Capital Maintenance — Breakdown Maintenance

SCE recorded $26.230 million in 2023 and forecasts $29.166 million in 2024 and $30.020 million in 2025 for the Substation Capital Breakdown Maintenance program.[684] SCE states that the purpose of this program is to address substation

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[679] Ex. SCE-02, Vol. 5 at 97.

[680] Ex. SCE-02, Vol. 5 at 94-5.

[681] Ex. SCE-02, Vol. 5 at 98.

[682] Ex. SCE-02, Vol. 5 at 98.

[683] Ex. SCE-02, Vol. 5 at 101.

[684] Ex. SCE-02, Vol. 5 at 110.

breakdown maintenance work on critical substation equipment.[685] This program is uncontested.

10.1.2.10. Substation Claim

SCE recorded $0.0521 million in 2023 and forecasts $0.411 million in 2024 and $0.423 million in 2025 for the Substation Claim program. SCE states that the purpose of this program is to support repairing damage to the substation caused by a third-party.[686] This program is uncontested.

10.1.2.11. Capital-Related Expenses and Other

SCE recorded $19.076 million in 2023 and forecasts $23.834 million in 2024 and $31.774 million in 2025 for the Substation Capital-Related Expenses and Other program.[687] SCE states that this program area supports indirect works such as substation maintenance oversight, informational meetings, substation emergency equipment, tools, and work equipment.[688] This program is uncontested.

10.1.2.12. Capital-Related Expenses and Other (O&M)

For Capital-Related Expense and Other (O&M), SCE recorded $4.800 million for 2023, and forecasts $5.268 million for 2024 and $5.280 million for 2025.[689] This program area's activities cover substation management labor.[690] This program is uncontested.

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[685] Ex. SCE-02, Vol. 5 at 109-110.

[686] Ex. SCE-02, Vol. 5 at 110.

[687] Ex. SCE-13, Vol. 5 at 5, Table I-4 (lines 5-7).

[688] Ex. SCE-02, Vol. 5 at 110.

[689] Ex. SCE-02, Vol. 5 at 116.

[690] Ex. SCE-02, Vol. 5 at 115.

10.1.2.13. Grid Monitoring and Operability

SCE recorded $96.841 million in 2023 and forecasts $77.540 million in 2024 and $160.891 million in 2025 for the Grid Monitoring and Operability program. SCE states that this program area supports SCE's communications network, Grid Data Center, copper wire replacement program, data and voice network replacements, fiber optic replacement program, microwave replacement program, transmission network and facilities program, and technology refresh program.[691] This program is uncontested.

10.2. Parties' Positions

10.2.1. Cal Advocates

10.2.1.1. Substation O&M: Grid Monitoring and Operability

In response to SCE's Grid Monitoring and Operability forecast, Cal Advocates recommends $102.330 million rather than SCE's forecast of $141.624 million. In support of its position Cal Advocates argues that SCE should only be authorized $50.345 million for substation monitoring and operating expenses.[692] Cal Advocates opposes SCE's forecast and its methodology asserting that its forecast results from an arbitrary method of forecasting an increase in fulltime equivalents.[693]

10.2.1.2. Substation O&M: Monitoring Bulk Power Systems

Cal Advocates recommends a reduction to SCE's Monitoring Bulk Power Systems forecast. For the labor expenses associated with this cost category, Cal Advocates recommends that the Commission authorize $36.911 million for

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[691] Ex. SCE-02, Vol. 5 at 35.

[692] Ex. CA-02 at 11.

[693] Cal Advocates OB at 86.

labor.[694] Cal Advocates states that it based its labor forecast of $36.911 million on a three-year average of SCE's 2020-2022 recorded labor expenses.[695]

With respect to non-labor expenses associated with this cost category, Cal Advocates recommends the Commission authorize $13.212 million. To support its position, Cal Advocates argues that SCE provides no specific detail to support its requested increase. Cal Advocates also asserts that SCE's methodology should have relied on a five-year recorded average of its non-labor expenses.[696]

10.2.1.3. O&M: Other Expenses

Cal Advocates recommends that the Commission should authorize $1.831 million for SCE's Other Expenses funding.[697] Cal Advocates argues that SCE previously underspent its 2021 GRC authorized revenues in 2021-2022 and opposes the methodology SCE used to develop its current Other Expenses forecast.[698]

10.2.1.4. Substation Inspections and Maintenance: Relay Inspection and Maintenance

Cal Advocates recommends that the Commission should authorize $23.855 million for SCE's Substation Inspections and Maintenance Business Plan Enterprise in TY 2025.[699]

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[694] Cal Advocates OB at 88.

[695] Ex. CA-02 at 14.

[696] Cal Advocates OB at 89.

[697] Ex. CA-02 at 16.

[698] Ex. CA-02 at 16.

[699] Ex. CA-02 at 17.

With respect to SCE's Relay Inspection and Maintenance activity in this cost category for TY 2025, Cal Advocates recommends that the Commission should authorize $2.184 million. Cal Advocates asserts that its proposal reflects the declining trend and historic underspending of SCE's Relay Inspection and Maintenance activity while appropriately funding its ongoing activities.[700] Cal Advocates claims SCE's forecast does not account for the declining trend.[701]

10.2.1.5. Other Substation Equipment Inspections and Maintenance

Cal Advocates opposes SCE's forecast for the Other Substation Equipment Inspections and Maintenance category. Cal Advocates asserts that SCE has not provided documentation to justify and demonstrate that it requires $2.304 million annually ($9.216 million over the four-year rate case cycle) to move equipment to the Edison Training Academy. Thus, Cal Advocates recommends that the Commission should authorize $1.748 million for SCE's Other Substation Equipment Inspections and Maintenance activity in TY 2025, which is $3.197 million less than SCE's TY 2025 request.[702]

10.2.1.6. Substation Capital: Transformer Bank Replacement Program

For SCE's Substation Transformer Bank Replacement Program capital expenditures, Cal Advocates recommends that the Commission should authorize $49.658 million for 2023, $65.627 million for 2024, and $55.024 million for 2025.[703] Cal Advocates opposes SCE's Substation Transformer Bank Replacement

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[700] Ex. CA-02 at 19.

[701] Cal OB at 90.

[702] Ex. CA-02 at 20.

[703] Cal Advocates OB at 93.

Program methodology. Cal Advocates recommends continued funding of the Substation Transformer Bank Replacement Program at historic levels. Cal Advocates asserts that SCE has not justified its claims to support an increase in this cost category.[704]

10.2.1.7. Substation Capital: Edison Training Academy

Cal Advocates recommends that the Edison Training Academy should be completed prior to more funding being approved for it.[705] Cal Advocates asserts that the Edison Training Academy is still in an early phase, and only a small fraction of the approved funding has been spent.[706]

Thus, Cal Advocates recommends that the Commission authorize memorandum-account treatment for capital expenditures associated with T&D Equipment for the Edison Training Academy. Cal Advocates reasons that this memorandum-account treatment would result in a recommended $41.611 million for TY 2025 for Substation Preventive Maintenance, which is $3.482 million less than SCE's $45.093 million request, and would provide the potential for cost recovery of the adjusted amount in future rate cases.[707]

10.2.2. TURN

10.2.2.1. Substation Infrastructure Replacement: Circuit Breaker Replacement Program

TURN makes an array of recommendations for SCE's Circuit Breaker Replacement Program. TURN recommends the following: (1) the Commission

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[704] Cal Advocates OB at 94.

[705] Ex. CA-22 at 13-14.

[706] Ex. CA-22 at 13-14.

[707] Ex. CA-09 at 24.

should authorize $153.13 million rather than SCE's forecast of $164.29 million for the 2023-2025 period which is a reduction of approximately 6.8 percent; and (2) the Commission should direct SCE to target replacement of only those circuit breakers that are deemed to be in "poor" or "very poor" condition.[708] TURN asserts Circuit breakers in "very good," " good," and "fair" condition should not be replaced.[709]

For SCE's next GRC, TURN proposes an array of recommendations. TURN advocates that: (1) SCE should present a more detailed analysis of unit costs, and break out its circuit breaker proposals into more granular voltage classes, rather than relying on two broad classes; (2) substantiate the accuracy of its chosen health index, or to modify that index to comport with TURN's suggestion of a linear, unbiased index; and (3) develop a replacement approach that establishes the need to replace substation equipment that fails earlier than a designated age threshold.[710]

10.2.2.2. Substation Infrastructure Replacement: Transformer Bank Replacement Program

With respect to SCE's Substation Transformer Bank Replacement Program, TURN recommends that the Commission authorize funding of $152.93 million rather than $182.00 million for the 2023-2025 period. This results in a reduction of approximately 6.9 percent to SCE's forecast. TURN asserts that this level of

[708] TURN OB at 91-92.

[709] TURN OB at 91-92.

[710] TURN OB at 91-92.

funding is consistent with replacement of 86 transformer banks from 2023-2025, as opposed to SCE's proposal of 98 for the same period.[711]

TURN also makes several other recommendations. First, TURN recommends that the Commission direct SCE to target replacement of only those substation transformers that are deemed to be in "poor" or "very poor" condition according to SCE's non-linear Health Index. TURN asserts that transformers in "very good," "good," and "fair" condition should not be replaced as part of the Infrastructure Replacement Program. Next, TURN recommends that the Commission should direct SCE to develop a replacement approach that establishes the need to replace substation transformer banks above an age-based threshold that relies on historical data of in-service failures. TURN proposes that for equipment that has not reached a specified age threshold, SCE should be required to demonstrate that all preventive, refurbishment, and other maintenance measures have been exhausted before justifying replacement.[712]

10.2.3. SCE's Rebuttal to Cal Advocates

10.2.3.1. O&M Expenses: Monitoring and Operating Substations

In response to Cal Advocates' opposition, SCE makes several arguments. First, SCE argues that its forecast accounts for resource needs during the 2025 GRC cycle.[713] SCE argues that its TY forecast supports the growth and change its enterprise will experience due to the employee compensation program as well as the growth in personnel required to continually maintain the safety and

[711] TURN OB at 94.

[712] TURN OB at 94.

[713] Ex. SCE-13, Vol. 5 at 9.

reliability of SCE's transmission and distribution systems.[714] Next, SCE testifies that its forecast reflects the average of total needs across the rate case years (2025-2028) which appropriately uses forecast growth from 2022 as a starting point to forecast its needs through 2028.[715]

10.2.3.2. Monitoring Bulk Power Systems

In response to Cal Advocates' opposition to SCE's Monitoring Bulk Power Systems forecast, SCE makes an array of arguments.

First, SCE opposes Cal Advocates' assertion that it did not justify its cost forecast. SCE asserts it provided substantial evidence that monitoring bulk power system costs will need to increase in 2025 to coincide with the deployment of the field area network and grid modernization applications as well as the growth of operational technology assets.[716]

Second, SCE asserts that Cal Advocates focuses narrowly upon the grid network solutions forecast while completely ignoring the grid control center. Finally, SCE argues that Cal Advocates uses an inconsistent forecast methodology that does not reflect the growing needs for monitoring bulk power systems.[717]

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[714] Ex. SCE-13, Vol. 5 at 10.

[715] Ex. SCE-13, Vol. 5 at 9-10.

[716] Ex. SCE-13, Vol. 5 at 14-17.

[717] Ex. SCE-13, Vol. 5 at 17-18.

10.2.3.3. O&M Expenses: Relay Inspections and Maintenance

SCE states it agrees with Cal Advocates' evaluation of the historical spend for Relay Inspections and Maintenance, which shows a decrease in recorded costs in 2020-2022.[718]

However, SCE asserts that the last year of recorded costs would not provide SCE with the necessary funding for the 2025 GRC cycle.[719] SCE states that annual costs for this activity can vary from year to year based on a number of factors, which include: (1) variances such as annual differences in the number of relays requiring maintenance; (2) different inspection cycles based on the relay type and equipment voltage; and (3) off-cycle inspections due to a need to change relay settings.[720] Thus, SCE contends that the number of relays installed on the system that require regular inspection and maintenance is not decreasing over time.

10.2.3.4. Other Substation Equipment: Inspections, Maintenance, and Preventive Maintenance

SCE asserts that the Commission should reject Cal Advocates' recommendation of complete denial of funding for the Edison Training Academy project. SCE argues that project delays outside of its control have affected the implementation of this program.[721] SCE testifies that the project is on track for

[718] Ex. SCE-13, Vol. 5 at 21.

[719] Ex. SCE-13, Vol. 5 at 21-22.

[720] Ex. SCE-13, Vol. 5 at 22.

[721] SCE RB at 205.

completion in 2028. Therefore, SCE asserts that the Commission should reject Cal Advocates' recommendation to deny the program's funding.[722]

10.2.3.5. Substation Infrastructure Replacement Program: Transformer Bank Replacement Program

SCE asserts that Cal Advocates' position toward its Transformer Bank Replacement Program is flawed for several reasons. First, SCE asserts that Cal Advocates' methodology to use 2018-2022 averages does not reflect current project costs. SCE states that Cal Advocates' methodology is not reflective of the actual expenditures that SCE reasonably expects to incur.[723]

Second, SCE asserts that Cal Advocates' characterization that the number of substation transformers that should be considered poor or very poor is not increasing is incorrect and that the evidence is clear that if SCE's forecast is authorized, SCE would still only be addressing a fraction of the current count of transformers that have already been assessed to be in very poor or poor condition.[724]

10.2.4. SCE's Rebuttal to TURN

10.2.4.1. Circuit Breaker Replacement Program

In response to TURN, SCE makes a series of rebuttal arguments regarding the Circuit Breaker Replacement Program. SCE asserts that: (1) TURN distorts the comparison of cost per circuit breaker versus replacement rate, and ignores current project realities;[725] (2) TURN incorrectly asserts that SCE's Health Index

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[722] SCE RB at 205.

[723] SCE OB at 83.

[724] Ex. SCE-13, Vol. 5 at 28.

[725] Ex. SCE-13, Vol. 5 at 33-35.

skews asset health;[726] (3) TURN confuses SCE's determination of circuit breaker scope of work; (4) SCE's Weibull Reliability Model approach is reasonable;[727] and (5) TURN incorrectly asserts that only oil and air magnetic circuit breakers may be the best candidates for replacement.[728] In short, SCE asks the Commission to reject TURN's recommendations and arguments.

10.2.4.2. Transformer Bank Replacement Program

SCE argues that TURN's position toward its Transformer Bank Replacement Program is incorrect and flawed. SCE argues that TURN's recommendation assumes that all assets are from the same manufacturer, in perfect conditions and identical specifications, located in the same environments, exposed to the same elements, and operate under the exact same circumstances.[729] SCE asserts that it operates a 50,000-square mile service area across drastically different climate zones, topographies and areas of vastly different service needs and therefore, it is illogical for TURN to presume that all transformers will perform the same way.[730]

SCE states that its strategy optimizes the full life cycle of each transformer and seeks to make the most informed decisions, as opposed to the "blunt instrument" of a generalized age-based replacement policy as proposed by TURN.[731] SCE asks the Commission to reject TURN's proposal.

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[726] Ex. SCE-13, Vol. 5 at 36.

[727] Ex. SCE-13, Vol. 5 at 39-40.

[728] Ex. SCE-13, Vol. 5 at 40.

[729] SCE OB at 88.

[730] Ex. SCE-13, Vol. 5 at 41-42.

[731] Ex. SCE-13, Vol. 5 at 42-43.

10.3. Discussion

10.3.1. Contested Programs

10.3.1.1. Substation O&M: Monitoring and Operating Substations

We adopt and authorize Cal Advocates' proposed forecast of $50.354 million plus an adjustment of $1.242 million for changes to the employee compensation program. This amounts to a total forecast of $51.596 million.

We find that Cal Advocates provides a reasonable alternative forecast for growth in this activity. However, Cal Advocates' forecast does not fully account for the changes to the employee compensation program. Thus, we apply an adjustment of $1.242 million.

In conclusion, we authorize and adopt a total forecast of $51.596 million for the Monitoring and Operating Substations activity.

10.3.1.2. Substation O&M: Monitoring Bulk Power Systems

For the Grid Control Center sub-activity, we find SCE's $12.705 million forecast reasonable and adopt the forecast.

For the Grid Network Solutions sub-activity, we agree with Cal Advocates that SCE does not justify its labor, non-labor, and other forecast increases. Although SCE provides titles of positions, blended average labor rates, and general descriptions of the work for categories of work included,[732] SCE does not provide documentation that clearly ties and quantifies the growth in these areas from 2022-2025 to its incremental full time employees and itemized costs. Absent additional information, it is difficult to assess these costs. This is a particular

[732] WP SCE-02, Vol. 05 at 13-22.

concern given the historic underspending for this activity[733] and the requested increase over base year spending.[734]

However, we decline to adopt Cal Advocates' forecast, which as SCE notes, does not discuss nor separate out the Grid Control Center sub-activity.[735] Therefore, we adopt the 2022 recorded expenses for labor, non-labor, and other costs for the Grid Network Solutions sub-activity[736] with an additional adjustment of $1.948 million to account for changes in the employee compensation program.[737] This amounts to an O&M forecast of $40.258 million for Grid Network Solutions.

Combining the authorizations for the Grid Network Solutions and Grid Control Center sub-activities, we authorize a TY forecast of $52.963 million for Monitoring Bulk Power Systems.

10.3.1.3. Inspections and Maintenance O&M Expenses: Relay Inspections and Maintenance

We authorize and adopt Cal Advocates' proposal for SCE's Relay Inspections and Maintenance activities for TY 2025. This results in a $2.184 million authorization for the activities associated with these costs.

We agree with Cal Advocates that SCE's TY forecast does not account for the decline in its Relay Inspection and Maintenance activities within the last five

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[733] Ex. SCE-02, Vol. 05 at 21 (Figure II-10).

[734] Percent increase based on $73.357 million requested in 2025 and $38.311 million recorded in 2022.

[735] Ex. SCE-13 Vol. 05 at 17-18.

[736] $25.356 million for labor, $11.123 million for non-labor, and $1.831 million for other. (See Ex. SCE-02, Vol. 05 at 18, Figure II-9).

[737] Ex. SCE-13, Vol. 05 at 18.

recorded years. Furthermore, SCE has underspent its authorized funding for these activities in previous years. For example, SCE recorded $2.834 million, which is $0.649 million less than SCE's 2021 GRC authorized expenses of $3.484 million. In 2022, SCE recorded $2.184 million, which is $1.299 million less than its 2021 GRC authorized expenses.[738] SCE attributes underspending for Relay Inspections and Maintenance work activities in the 2021 GRC to the increased number of off-cycle inspections to install more sensitive fault settings on the relay populations associated with distribution circuits that traverse high fire risk areas, which resulted in faster fault clearing times in these high fire risk areas.[739] However, as Cal Advocates points out, SCE does not incorporate the 2021 savings due to faster fault clearing times in its TY forecast, even though it incorporates 2018-2020 recorded expenses.[740] Nor does SCE identify the specific accounts or line-item details associated with the activities that ultimately received the reallocated, 2021-2022 authorized funding.[741]

Therefore, we adopt and authorize Cal Advocates' $2.184 million recommendation, finding it reasonable given the declining trends and historic underspending associated with these activities.

10.3.1.4. Inspections and Maintenance O&M Expenses: Other Substation Equipment Inspections and Maintenance

We authorize and adopt Cal Advocates' proposal for SCE's Other Substation Equipment Inspections and Maintenance activities for TY 2025. This

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[738] Ex. CA-02 at 18.

[739] Ex. SCE-02, Vol. 5 at 85; *see also* Ex. CA-02 at 18.

[740] Ex. CA-02 at 18.

[741] Ex. CA-02 at 19.

results in a $1.748 million authorization for the activities associated with these costs.

We agree with Cal Advocates that SCE has not provided an adequate justification demonstrating that it requires an increase of 234.57 percent or $2.304 million annually ($9.216 million over the four-year rate case cycle) to move equipment to the Edison Training Academy.[742] We therefore authorize $1.748 million for SCE's Other Substation Equipment Inspections and Maintenance activities in TY 2025, which is $3.197 million less than SCE's TY 2025 request.

10.3.1.4.1. Preventive Maintenance

We also adopt Cal Advocates' recommendation for memorandum-account treatment for capital expenditures associated with T&D Equipment for the Edison Training Academy. Cal Advocates reasons that this memorandum-account treatment would result in a $3.482 million reduction of its test year request, and would provide the potential for cost recovery of the adjusted amount in future rate cases.[743] We direct SCE to record these amounts in the memorandum account for Edison Training Academy discussed in Enterprise Operations. In short, we adopt and authorize Cal Advocates' $1.748 million recommendation, finding it reasonable.

10.3.1.5. Substation Infrastructure Replacement: Substation Transformer Bank Replacement Program

We authorize and adopt $44.530 million recorded for 2023 and TURN's proposal of $57.859 million for 2024, and $49.060 million for 2025.

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[742] Ex. CA-02 at 20.

[743] Ex. CA-09 at 24.

We find that SCE has not justified its request through tis forecast methodology. We agree with TURN that SCE should provide transparent, empirical evidence for Health Index weightings and classifications.[744] TURN's proposal provides a reasonable forecast for prudently allocating costs for replacement.[745] Therefore, we authorize and adopt $44.530 million recorded for 2023 and TURN's proposal of $57.859 million for 2024, and $49.060 million for 2025.

10.3.1.6. Circuit Breaker Replacement Program

We authorize and adopt $55.348 million recorded for 2023, and TURN's proposal of $53.588 million for 2024 and $51.884 million for 2025.

We are unpersuaded by the arguments and evidence presented by SCE that its forecast methodology is reasonable. We find that TURN's proposal provides a reasonable forecast for circuit breaker replacement that appropriately balances risk and safety against costs born by ratepayers. Thus, we authorize and adopt $55.348 million recorded for 2023, and TURN's proposal of $53.588 million for 2024 and $51.884 million for 2025.

10.3.2. Uncontested Programs

The following recorded costs and forecasts are uncontested. SCE has justified the reasonableness of these uncontested forecasts and therefore, we find reasonable and approve these activities and their recorded and forecast costs:

- Capital-Related Expenses and Other — $19.076 million recorded for 2023, $23.834 million forecasted for 2024, and $31.774 million forecasted for 2025;

[744] Ex. TURN-05E at 28.

[745] Ex. TURN-05E at 30.

- Capital-Related Expense and Other (O&M) — $4.800 million recorded for 2023, $5.268 million forecasted for 2024, and $5.280 million forecasted for 2025;
- Circuit Breaker Inspection Maintenance Program — $7.338 million;
- Equipment Washing Program — $1.634 million;
- Grid Monitoring and Operability (Capital) — $96.841 million recorded in 2023, $77.540 million forecasted in 2024, and $160.891 million forecasted for 2025;
- Minor Equipment and Supplies Program — $2.735 million;
- Relays Protection and Control Replacement Program — $80.736 million recorded for 2023, $79.146 million forecasted for 2024, and $91.197 million forecasted for 2025;
- Substation Capital Maintenance (Breakdown Maintenance) — $26.230 million recorded for 2023, $29.166 million forecasted for 2024, and $30.020 million forecasted for 2025;
- Substation Claim — $0.521 million recorded for 2023, $04.11 million forecasted for 2024, and $0.423 million forecasted for 2025;
- Substation Infrastructure Replacement Program (Substation Rebuild Program) — $85.045 million recorded for 2023, $76.497 million forecasted for 2024, and $72.339 million forecasted for 2025;
- Substation Inspections and Maintenance (Hydro) — $1.043 million;
- Substation O&M Breakdown Maintenance — $2.750 million; and
- Transformer Inspection and Maintenance program — $4.423 million.

11. Grid Modernization, Grid Technology, and Energy Storage

11.1. Grid Modernization Programs

11.1.1. Uncontested Programs

No party contested SCE's forecasts for the following four categories of capital expenditures for Grid Modernization: Engineering & Planning Software Tools,[746] Grid Management System, Communications, and DER Hosting Capacity Reinforcement. We summarize these uncontested programs below.

11.1.1.1. Engineering and Planning Software Tools

For 2023-2025, SCE forecasts $81.641 million for Engineering and Planning Software Tools.[747] For this GRC period, SCE states that it will utilize the Engineering and Planning Software Tools to deliver enhanced planning capabilities and address challenges with implementing system-wide load flow analysis. Furthermore, SCE states that the activities captured in this program area will help SCE transition to profile-based capacity planning. SCE states that the Engineering and Planning Software Tools will enable it to create a dashboard that aggregates information from the various engineering and planning software which will enable SCE system planners to evaluate the grid system and generate planning summaries.[748] Finally, SCE states that the scope of work planned for

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[746] While Cal Advocates does not oppose SCE's request for Engineering & Planning Software Tools, Cal Advocates does recommend that the Long Term Planning Tool, System Modeling Tool, and DRP External Portal use the Blanket-Specific 12/1/9999 in-service date designation in the RO model. *See* Ex. CA-05 at 7. We note that SCE states it agrees that the 12/1/9999 in-service date designation should be used, but because making this change at this time would increase the revenue requirement, SCE proposes to make this change in its next GRC. *See* Ex. SCE-13, Vol. 06 at 17-18.

[747] Ex. SCE-02, Vol. 6 at 35.

[748] Ex. SCE-02, Vol. 6 at 39.

the activities within this grid modernization category will enable it to: (1) perform end-to-end planning for multiple growth scenarios; (2) improve the accuracy of SCE's forecasting process by transitioning from circuit-level forecasting to transformer structure-level forecasting; (3) accelerate the consideration of DERs as potential grid solutions upfront within the capacity planning process; and (4) improve SCE's project and portfolio management processes and tools.[749] The Engineering and Planning Software Tools capital program is uncontested.

11.1.1.2. Grid Management System

For 2023-2025, SCE forecasts $131.357 million for its Grid Management System (GMS). SCE's GMS is an advanced software platform that integrates multiple systems designed to monitor, manage, and optimize the performance of the increasingly dynamic electric grid characterized by high DER penetration. The GMS is replacing SCE's legacy Distribution Management System (DMS) and Outage Management System (OMS) and will introduce more advanced distribution and outage management functions. SCE testifies that the GMS will also enable monitoring, management and optimization of DERs, load and power quality management, and microgrid management.[750] The GMS capital program is uncontested.

11.1.1.3. Communications

For 2023-2025, SCE forecasts $255.748 million for its Communications capital program. SCE testifies that its new Field Area Network (FAN) is a critical component of the Grid Modernization program, enabling real-time, cyber-secure

[749] Ex. SCE-02, Vol. 6 at 39.

[750] Ex. SCE-02, Vol. 6 at 64-66.

communications between grid devices (including DERs), distribution substations, and SCE's operations control centers.[751] SCE also testifies that the FAN directly enables various grid management functions, including real-time situational awareness, analyzing and resolving grid reliability issues, and integrating and managing DERs. SCE states its new FAN will also enable secure integration with DER aggregators and other third parties, which will support the use of DERs to provide reliability services to the distribution system. Finally, SCE states it decided to adopt a more streamlined design for the common substation platform which requires additional lab testing of the platform as well as validation of the cybersecurity control functionality.[752] The Communications capital program is uncontested.

11.1.1.4. DER Hosting Capacity Reinforcement

For 2023-2025, SCE forecasts $2.253 million for its DER Hosting Capacity Reinforcement capital program. This program is targeted at performing the necessary circuit upgrades to support integration of DERs forecasted in the IEPR DER forecast.[753] The DER Hosting Capacity Reinforcement capital program is uncontested.

11.1.2. Contested Programs

11.1.2.1. DER-driven Distribution Automation

For 2023-2025, SCE forecasts $147.534 million for its DER-driven Distribution Automation (Automation) forecast. SCE testifies that its proposed Automation program offers an array of benefits. SCE states the Automation program will: (1) collect real-time grid information to improve grid operator

[751] Ex. SCE-02, Vol. 6 at 86.

[752] Ex. SCE-02, Vol. 6 at 89.

[753] Ex. SCE-02, Vol. 6 at 118-122.

situational awareness; (2) enable automatic detection of fault events and faster fault isolation and service restoration; (3) improve operational flexibility to avoid potential overload conditions; and (4) reconfigure the grid following fault events using DERs to support the reconfigurations if necessary.[754] The DER-driven Distribution Automation program is contested by TURN, which we discuss in further detail, below.

11.1.2.2. Grid Modernization O&M Expenses: T&D Deployment Readiness and IT Project Support

For 2023-2025, SCE's total TY 2025 O&M forecast for Grid Modernization is $6.544 million. There are two O&M activities: (1) T&D Deployment Readiness; and (2) IT Project Support. For T&D Deployment Readiness, SCE's TY 2025 O&M forecast is $1.591 million.[755] For IT Project Support, SCE's TY 2025 O&M forecast is $4.952 million.[756]

First, SCE testifies that T&D Deployment Readiness helps to ensure that the T&D organization and its workforce are prepared to implement the new distribution and substation automation technologies in SCE's Grid Modernization Plan (GMP).[757] Second, IT Project Support includes O&M expenses associated with implementing the Engineering and Planning Software Tools, GMS, and Communications capital deployments.[758] Cal Advocates

[754] Ex. SCE-02, Vol. 6 at 97.

[755] Ex. SCE-13, Vol. 6 at 4.

[756] Ex. SCE-13, Vol. 6 at 7.

[757] Ex. SCE-13, Vol. 6 at 4.

[758] Ex. SCE-13, Vol. 6 at 4.

recommended reductions to both O&M activities, which are further discussed below.

11.1.2.3. Grid Technology O&M

SCE's TY 2025 O&M forecast for Technology Assessment is $15.102 million. Grid Technology Assessment is the only O&M activity in SCE's 2025 GRC request related to Grid Technology. Technology Assessment activities include technology testing and advanced systems studies designed to help SCE better understand and identify solutions for improving grid planning and operations. Cal Advocates recommends a reduction of $9.518 million to SCE's TY 2025 forecast as discussed below.[759]

11.1.2.4. Grid Technology Capital Projects

For 2023-2025, SCE forecasts $30.565 million in capital expenditures for Grid Technology Capital Projects. This includes recorded 2023 expenditures of $10.620 million.[760] These capital expenditures relate to two activities: Grid Technology Laboratories and Capital Pilot Projects. No intervenor contested SCE's Grid Technology Laboratories forecast.

With respect to SCE's Capital Pilot Projects, its 2024-2025 forecast is $11.541 million. This activity encompasses pilots that SCE states are needed for field installations of technology that has proven successful in Electric Program Investment Charge (EPIC) demonstrations.[761] SCE states that these pilots will enable it to timely and reliably test whether this technology is safe, reliable, and affordable in greater aggregation across different geographic areas.[762]

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[759] SCE OB at 95.

[760] SCE OB at 98.

[761] Ex. SCE-13, Vol. 6E2 at 27E2.

[762] Ex. SCE-13, Vol. 6 at 27.

Specifically, SCE is seeking funding for six pilot projects. These pilot programs are focused on: (1) providing better grid resiliency to essential community facilities (Smart City); (2) reducing reliance on proprietary legacy substation control hardware in favor of modern standardized technologies (Virtual Programmable Automation Controller); (3) virtualization of appliance-based protection equipment to better utilize the flexibility and interoperability of substation process bus (Virtual Protection); (4) adaptive protection to enhance grid operational reliability under changing conditions (Adaptive Protection); (5) battery energy storage connectivity with DC Link to improve operational flexibility between load circuit transfers (DC Link); and (6) advanced alternative service and control methods for high-power and high-energy electric transportation fleet depots (Service Center of the Future).[763]

Cal Advocates, the only intervenor to contest this forecast, recommends zero dollars. We discuss Cal Advocates' position in further detail below.

11.1.2.5. Energy Storage O&M

SCE's total TY 2025 O&M forecast for Energy Storage is $12.360 million. This forecast covers three activities: (1) $1.679 million for the Distribution Energy Storage Integration activity (DESI); (2) $0.150 million for the Long Duration Energy Storage (LDES) activity; and (3) $10.531 million for Generation (*i.e.*, the Mira Loma and Reliability Utility-Owned Energy Storage (RUOES) sites).[764]

First, SCE states that the focus of DESI is to pilot new capabilities created by energy storage technology and to apply their results across associated benefit streams (*e.g.*, affordability, reliability, resiliency, and clean energy integration).

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[763] Ex. SCE-13, Vol. 6 at 27-28.

[764] Ex. SCE-13, Vol. 6 at 36, Table IV-20.

SCE testifies that along with integrating DERs into the electric system, the DESI pilots also provide a platform for developing tools and methods for where and how energy storage systems can add value for customers. SCE states its O&M request for DESI supports the planning and operations of the DESI program, including technology assessment and technology transfer (*e.g.*, documentation and implementation of lessons learned).[765]

Second, SCE states that the purpose of the LDES project is to facilitate adoption of new non-lithium-ion energy storage technologies that can enable meeting California's long-term policy goals for renewable integration utilizing more diverse methodologies than what is currently available. SCE testifies that the pilot facilitates adoption by serving as a vehicle for SCE and its industry partners to establish the new policies, procedures and technical specifications that must be in place before wider adoption can be implemented safely and reliably. SCE contends that diversification of energy storage technology options, which can be achieved through LDES, is also an important component of maintaining affordability as introducing new products on the market that can substitute for existing products serves to increase supply, giving SCE and its customers more buying power. Similar to DESI, SCE states that the O&M request for LDES will support the planning and operations of the LDES program, including technology assessment and technology transfer.[766]

Finally, SCE states that it performed emergency RUOES procurement pursuant to the July 30, 2021 Governor's Proclamation of a State of Emergency

[765] Ex. SCE-02, Vol. 6 at 162-163.

[766] Ex. SCE-02, Vol. 6. at 163-164.

pertinent to potential 2022 grid reliability outages.[767] Cal Advocates was the only intervenor to contest SCE's Energy Storage O&M forecast. We discuss Cal Advocates' position in further detail below.

11.1.2.6. Energy Storage Capital

For 2023-2025, SCE forecasts $39.177 million in capital expenditures for Energy Storage. These capital expenditures are associated with both DESI ($29.981 million) and LDES ($9.196 million).

SCE's 2023-2025 capital expenditures forecast for DESI is $29.981 million. These expenditures support capital upgrades for three operational systems and project close out of six additional systems to be deployed through 2025.[768] The only intervenor to contest SCE's capital expenditures forecast for DESI was Cal Advocates.

The remaining $9.196 million of SCE's Energy Storage capital expenditures forecast is associated with 2025 forecast costs for a preliminary LDES pilot. With the LDES pilot, SCE aims to utilize energy storage technology beyond lithium-ion to achieve energy storage for longer durations and/or at lower costs.[769] Cal Advocates also opposed this capital expenditure.

[767] SCE OB at 102.

[768] SCE OB at 107.

[769] SCE OB at 108.

11.2. Parties' Positions

11.2.1. Cal Advocates

11.2.1.1. Grid Modernization O&M: T&D Deployment Readiness and IT Project Support

Cal Advocates recommends $974,000 for SCE's T&D Deployment Readiness activity in TY 2025.[770] Cal Advocates' recommendation to reduce SCE's request is based on a three-year average of SCE's 2020-2022 recorded expenses, which Cal Advocates contends addresses the variability in SCE's T&D Deployment Readiness expenses and the historic underspending of its authorized revenues.[771] Cal Advocates asserts that SCE's T&D Deployment Readiness expenses have declined annually in 2020-2022 and thus, argues that a cost reduction to this area is reasonable.[772]

Next, with respect to SCE's IT Project Support, Cal Advocates recommends $3.45 million for SCE's IT Project Support expenses in TY 2025.[773] Cal Advocates' recommendation is based on a three-year average of SCE's 2020-2022 recorded expenses. Cal Advocates argues that SCE has not met its burden to demonstrate that its IT Project Support expenses will increase to $4.952 million in TY 2025 and should therefore be reduced.[774]

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[770] Ex. CA-02 at 22.

[771] Ex. CA-02 at 23.

[772] Ex. CA-02 at 23.

[773] Ex. CA-02 at 23.

[774] Ex. CA-02 at 24.

11.2.1.2. Grid Technology O&M

Cal Advocates recommends $9.518 million for SCE's Grid Technology O&M. Cal Advocates' recommendation is $5.584 million less than SCE's TY 2025 forecast of $15.102 million.[775]

Cal Advocates states it utilized SCE's 2022 recorded expenses to develop its TY 2025 forecast. Cal Advocates testifies that its recommendation is comparable to the recent recorded historical expenses for this activity.[776] Cal Advocates argues that SCE has not justified that it requires additional funding beyond its 2022 recorded expenses. Cal Advocates also argues that SCE has underspent its 2021 GRC authorized revenues.[777]

11.2.1.3. Grid Technology Capital Pilot Projects

Cal Advocates recommends that the Commission adopt $0 in capital expenditures over the 2023-2028 period to initiate SCE's Capital Pilot Projects, versus SCE's request for $46.955 million over the same period.[778] Specifically, Cal Advocates recommends a downward adjustment of: $1.642 million for 2023; $0.505 million for 2024; $11.035 million for 2025; $11.141 million for 2026; $11.238 million for 2027; and $11.393 million for 2028. This results in a total downward adjustment of $46.955 million.[779]

Cal Advocates states that SCE's 2023-2025 forecasts for its Distribution Grid capital activities for Capital Pilot Projects are based mostly on EPIC

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[775] Ex. CA-02 at 30.

[776] Ex. CA-02 at 30.

[777] Ex. CA-02 at 30.

[778] Cal Advocates OB at 103.

[779] Cal Advocates OB at 103.

program projects.[780] Cal Advocates states it is unreasonable for the Commission to waste ratepayer funding on these programs. Cal Advocates contends that SCE has failed to meet its burden for the Commission to authorize funding for any of these programs.[781] Cal Advocates states that in many cases, the project was either used and useful outside the GRC period or used and useful on the last possible day.[782]

11.2.1.4. Energy Storage O&M

Cal Advocates recommends that the Commission adopt $0.700 million for SCE's Energy Storage activities in TY 2025, which is $15.221 million less than SCE's TY 2025 forecast of $15.921 million.[783]

Cal Advocates used SCE's 2022 recorded costs to develop its recommendation. Cal Advocates' forecast excludes SCE's $13.626 million forecast for costs associated with the three RUOES sites.[784]

11.2.1.5. Energy Storage Capital

Cal Advocates recommends that the Commission adopt $38.647 million in capital expenditures over the 2023-2028 period for SCE's Grid Scale Storage Projects. Specifically, Cal Advocates recommends a downward adjustment of: $1.172 million for 2023; $2.166 million for 2024; $9.196 million for 2025; $12.605 million for 2026; $19.088 million for 2027; and $38.328 million for 2028. This results in a total downward adjustment of $82.555 million.[785]

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[780] Ex. SCE-02, Vol. 6 at 150.

[781] Cal Advocates OB at 106.

[782] Cal Advocates OB at 106.

[783] Cal Advocates OB at 136.

[784] Cal Advocates OB at 136.

[785] Cal Advocates OB at 126.

11.2.2. TURN

11.2.2.1. Automation

TURN proposes reductions to SCE's Reliability-driven and DER-driven Distribution Automation forecasts for 2025-2028.

For Reliability-driven Distribution Automation, TURN recommends $25.050 million for 2025, compared to SCE's forecast of $53.006 million. For DER-driven Distribution Automation, TURN recommends $6.600 million for 2025, compared to SCE's forecast of $20.956 million.[786] TURN contends that SCE's forecasts should be reduced for ratepayer affordability purposes.[787]

11.2.2.2. Energy Storage: LDES

TURN argues that the Commission should reject SCE's proposal for LDES capital expenditures of $19.088 million for 2027 and $38.328 million for 2028. TURN also recommends that any approval for LDES investments be accompanied by annual progress reports that summarize the status of the project, funds expended, and lessons learned.[788] Additionally, while TURN opposes SCE's proposed 2027 and 2028 expenditures for post-pilot projects and technology enhancements on the basis that these proposed investments are not adequately supported, TURN does not oppose SCE's proposed 2025 and 2026 capital expenditures.[789]

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[786] Ex. TURN-06E at 7, Table 2.

[787] Ex. TURN-06 at 6.

[788] Ex. TURN-06 at 8-9.

[789] Ex. TURN-06 at 9-10.

11.2.3. SCE's Rebuttal to Cal Advocates

11.2.3.1. Grid Modernization O&M: T&D Deployment Readiness and IT Project Support

In response to Cal Advocates, SCE offers its rebuttal. First, SCE states that Cal Advocates' reduction of this program is erroneously based solely on its observation that SCE's T&D Deployment Readiness expenses declined annually between 2020 and 2022.[790] SCE argues that focusing solely on historical expenses inappropriately ignores the substantial effort SCE will undertake in 2024 and 2025 for Organizational Change Management (OCM) activities to support the implementation of new distribution automation technologies from 2025 to 2028. SCE contends that successful realization of SCE's distribution automation capabilities and benefits depends on the successful transition of SCE's grid planners and operators to using several new distribution automation technologies.[791]

Second, SCE asserts that its IT Project Support forecast is reasonable and should be approved. SCE states that the level of SCE's IT Project Support non-labor expenses coincides with deployment activities.[792] Third, SCE asserts that it has demonstrated that there is nearly a two-fold increase in the need of full-time equivalents for 2025.[793] SCE states that this forecast in full-time equivalents is consistent with the expected increase in "seat time" training that

[790] SCE OB at 90.

[791] Ex. SCE-13, Vol. 6 at 5.

[792] Ex. SCE-13, Vol. 6 at 8.

[793] Ex. SCE-13, Vol. 6 at 9-10.

will coincide with the initial Grid Management System Phase 1 distribution and outage management function deployments taking place beginning in 2024.[794]

11.2.3.2. Grid Technology O&M

Next, in rebuttal to Cal Advocates' recommendation to reduce the Grid Technology O&M forecast by $5.584 million, SCE makes three primary arguments. SCE contends that: (1) it provided substantial justification for needing additional funding beyond its 2022 recorded expenses in 2025; (2) SCE spent less than authorized in 2021 due to COVID-19 and wildfire mitigation prioritization — not a decreased need for grid technology work; and (3) SCE is forecasting more fulltime equivalents in 2025 compared to 2022, not fewer.[795]

11.2.3.3. Grid Technology Capital Pilot Projects

In rebuttal to Cal Advocates' recommendation to disallow the entirety of SCE's 2024-2025 forecast for this category, SCE makes three primary arguments. First, SCE asserts that Cal Advocates' contention that SCE failed to demonstrate that these pilots would address problems unique to SCE is wrong and evidences a misunderstanding of the purpose and need for these pilots.[796] SCE argues that when EPIC demonstrations prove successful, SCE then needs to pilot that technology, at a scale larger than a demonstration allows, in order to establish the long-term support, training, and installation standards necessary for the technology solution to be part of SCE's operations.[797] In support, SCE states that

[794] Ex. SCE-13, Vol. 6 at 9.

[795] Ex. SCE-13, Vol. 6 at 23-24; Ex. SCE-02 Vol. 6 at 136.

[796] Ex. SCE-13, Vol. 6 at 29.

[797] Ex. SCE-13, Vol. 6 at 29.

each of the pilots addresses unique technical problems that would enhance its grid.[798]

Second, SCE asserts that while the benefits of these pilots cannot be quantified, there are still significant benefits. For example, SCE argues that Cal Advocates' criticism that SCE has not conducted any cost-benefit analysis for these pilots is misplaced. SCE states that it has demonstrated that doing a cost-benefit analysis for these projects would not adequately represent the potential benefits as not all of these benefits can be quantified. SCE contends that the entire point of conducting a pilot is to gain a better understanding of technologies and processes and to establish SCE standard practices around a particular technology or application in a smaller, more cost-effective setting prior to deploying such technologies or processes at scale.[799]

Finally, SCE states that it is forecasting that five of the six pilots will be used and useful during this GRC period, while spending for the sixth pilot needs to begin during this GRC period. In essence, SCE argues that Cal Advocates' contention that SCE cannot ensure these pilots will be "used and useful" during this GRC window is not a basis for denying SCE funding.[800]

11.2.3.4. Energy Storage O&M

In response to Cal Advocates' reduction of SCE's proposed Energy Storage O&M, SCE makes an array of rebuttal arguments.

First, SCE argues that it is not appropriate or reasonable to deny SCE necessary funding to maintain RUOES sites. SCE asserts that it performed

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[798] SCE OB at 99-101.

[799] Ex. SCE-13, Vol. 6 at 32.

[800] Ex. SCE-13, Vol. 6 at 33.

emergency procurement in compliance with the July 30, 2021 Governor's Proclamation of a State of Emergency which resulted in procuring three storage systems totaling 537.5 MW.[801] Further, SCE states that these sites were not in service in 2022, which means that the 2022 recorded costs do not reflect any of the necessary maintenance costs that SCE will incur for these sites.[802]

Second, SCE states Cal Advocates' opposition to the inclusion of the entirety of the contractual fixed fees for RUOES maintenance in SCE's Energy Storage forecast is unreasonable.[803] SCE states that it has adequately justified its normalized Test Year forecast of $10.531 million for the Generation component of SCE's Test Year Energy Storage O&M forecast.[804]

Third, SCE asserts that the 2022 recorded amount would not provide sufficient funding for the DESI pilots because more DESI pilots will be operational in 2025 compared to 2022.[805] SCE argues that its 2025 TY expenses for the DESI pilots will naturally be higher than the recorded expenses in 2022 because more DESI pilots will be operational in 2025 versus 2022. In 2022, SCE testifies that only three DESI pilots were operational: DESI 1, DESI 2, and Mercury 4. However, SCE contends that between 2022 and 2025, an additional seven DESI pilots will become operational: Mercury 1, Mercury 2, Gemini 1, Gemini 2, Apollo 1, Apollo 2, and Gemini 3. Thus, SCE states it needs additional funding to support the additional number of DESI pilots in operation.[806]

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[801] SCE OB at 102-104.

[802] Ex. SCE-13, Vol. 6 at 37.

[803] SCE OB at 103-104.

[804] SCE OB at 105.

[805] Ex. SCE-13, Vol. 6 at 40-41.

[806] Ex. SCE-13, Vol. 6 at 40-41.

11.2.3.5. Energy Storage Capital

For 2023-2025, SCE forecasts $39.177 million in capital expenditures for Energy Storage. These capital expenditures are associated with both DESI ($29.981 million) and LDES ($9.196 million).

With respect to SCE's 2023-2025 capital expenditure forecast for DESI, SCE states that these expenditures support capital upgrades for three operational systems and project close out of six additional systems to be deployed through 2025. In response to Cal Advocates' reduction of SCE's original 2023 forecast and its reduction to SCE's 2024 forecast, SCE states it agrees with Cal Advocates that the costs to perform upgrades on DESI 1 should be removed from SCE's forecast.[807] However, SCE states that to properly reflect SCE's changed plan to decommission DESI 1 rather than perform upgrades, the removal of those upgrade costs needs to be offset by the incremental cost for decommissioning, which SCE forecasts will be $0.384 million in 2024. Thus, SCE reduces its 2024 forecast by $1.782 million rather than the $2.166 million recommended by Cal Advocates.[808] These changes result in a revised DESI forecast of $29.981 million in capital expenditures.

Next, in support of its forecast, SCE argues that Cal Advocates' recommendation of $0 for LDES is unreasonable. SCE states that while it did not perform a traditional cost-benefit analysis, SCE has demonstrated the benefit of this project to ratepayers by showing: (1) this project can accelerate the commercialization of non-lithium-ion energy storage technologies, which can facilitate high renewables integration by acting as base generation replacement;

[807] SCE OB at 107.

[808] SCE OB at 107.

(2) this project will provide more flexibility and more reliability in the event of extreme conditions such as occurred in the August 2020 power emergencies; and (3) if commercialization of non-lithium-ion energy storage technologies is accelerated, flexibility, reliability, performance, and cost can be optimized by selecting the most appropriate technology for each deployment.[809]

SCE also argues that this project carries two key affordability benefits to ratepayers. SCE states that: (1)developing a non-lithium-ion technology will diversify energy storage technology options, giving buyers like SCE and its customers more buying power; and (2) the lessons learned from this project, in terms of implementation, decommissioning/recycling, and operational know-how with respect to non-lithium-ion systems, will allow SCE to deploy such systems on a more widespread scale in the future at lower cost and with a decreased time to deployment.[810]

11.3. Discussion

11.3.1. Contested Programs

11.3.1.1. Automation

The Commission has two questions presented before it regarding the Automation Program. The first question is whether the Commission should adopt and authorize the program. The second question is, if the Commission does authorize and adopt the Automation program, what the authorized funding should be.

First, we adopt and authorize the Automation program. The improved telemetry and switching capabilities provided by the Automation program will

[809] Ex. SCE-13, Vol. 6 at 45-46.

[810] Ex. SCE-13, Vol. 6 at 46.

improve SCE's ability to monitor and respond to real-time conditions on the distribution system. We find that this may enable SCE to mitigate potential safety hazards more quickly by reducing the potential for customer and workforce exposure to such hazards, reducing the number of customers impacted by outages, outage frequency, and outage duration. Additionally, we find that the Automation program may improve SCE's exposure to climate-driven grid vulnerabilities by increasing the value of, and need for, operational flexibility. This may allow SCE to respond and reconfigure the grid with more rapidity, in response to emerging grid threats or potential outage conditions, including PSPS events. Next, we consider the reductions to the program proposed by TURN.

TURN contested some of SCE's Automation forecasts. TURN proposes reductions to SCE's Reliability-driven and DER-driven Distribution Automation forecasts for 2025-2028. As discussed above, for Reliability-driven Distribution Automation, TURN recommends $25.050 million for 2025, compared to SCE's forecast of $53.006 million, while for DER-driven Distribution Automation, TURN recommends $6.600 million for 2025, compared to SCE's forecast of $20.956 million.[811] TURN asserts that the distribution automation investments should be viewed through the lens of reducing costs to ratepayers. We agree.

In conclusion, we find that the Automation program is reasonable and authorize and adopt it for SCE. However, for the Reliability-driven Automation program, we adopt $25.050 million for 2025 instead of SCE's forecast of $53.006 million. For DER-driven Distribution Automation, we adopt TURN's

[811] Ex. TURN-06E at 7.

recommendation of $6.600 million for 2025 instead of SCE's forecast of $20.956 million.

11.3.1.2. Grid Modernization O&M

Again, the Commission has two questions presented before it regarding the Grid Modernization O&M. The first question is whether the Commission should adopt and authorize the program. The second question is, if the Commission does authorize and adopt the program, what the authorized funding should be.

Under the Grid Modernization O&M program, there are two projects: (1) T&D Deployment Readiness; and (2) IT Project Support. We adopt and authorize the Grid Modernization O&M program. We find that this program will support implementation of new Grid Modernization technologies.

We decline to adopt Cal Advocates' reductions to the T&D Deployment Readiness and IT Project Support elements of the Grid Modernization O&M. We find that SCE's T&D Deployment Readiness forecast of $1.591 million is reasonable and is approved. The number of distribution automation devices, which include grid sensors and grid switchers, will increase in 2025. These devices will consist entirely of new, advanced switches that include telemetry and fault interrupting capabilities. The increase in these devices and as a consequence, their potential for increased complexity, support SCE's funding request in 2025 for T&D Deployment Readiness.

With respect to IT Project Support, we adopt and authorize SCE's 2025 TY O&M Forecast of $4.952 million. This forecast is based on the expected level of effort required to support the engineering and planning software tools and grid management system deployments through 2025. Thus, we decline to adopt Cal Advocates' reduction.

In conclusion, we authorize and adopt SCE's 2025 TY O&M forecast for Grid Modernization, which includes the T&D Deployment Readiness and IT Project Support, of $6.544 million.

11.3.1.3. Grid Technology O&M

Again, the Commission has two questions presented before it regarding the Grid Technology O&M. The first question is whether the Commission should adopt and authorize the program. The second question is, if the Commission does authorize and adopt the program, what the authorized funding should be.

We adopt and authorize the Grid Technology O&M program. These activities include technology testing and advanced systems studies designed to help SCE better understand and identify solutions for improving grid planning and operations. These activities are reasonable for SCE to conduct and thus, we authorize their implementation. The next question is whether we should adopt SCE's proposed forecast.

While we authorize and adopt this program, we adopt Cal Advocates' proposed labor forecast of $7.201 million and non-labor forecast of $2.317 million, plus an adjustment of $1.753 million for changes to the employee compensation program. This results in a total forecast of $11.271 million. We agree with Cal Advocates that SCE has not sufficiently justified the reasonableness of its forecast request. We are, therefore, persuaded by the arguments and evidence presented by Cal Advocates which lead us to authorize and adopt a total forecast of $11.271 million for this program.

11.3.1.4. Grid Technology Capital Pilot Projects

Again, we have two questions presented before us: whether the Commission should adopt and authorize the Capital Pilot Projects and if so, what the authorized funding should be.

Within the Grid Technology Capital Pilot Projects, there are two components. The first component is the uncontested SCE Grid Technology Laboratories' 2023-2025 forecast capital expenditure of $19.024 million. Since this forecast is uncontested, and SCE has demonstrated that the activities encompassing this program are reasonable, we authorize and adopt the forecast capital expenditures of $19.024 million for SCE's 2023-2025 Grid Technology Laboratories program. Next, we turn to the contested component of this program: Capital Pilot Projects.

Cal Advocates contested SCE's 2024-2025 forecast of $11.541 million for the Capital Pilot Projects. Cal Advocates recommends disallowing the full forecast. Cal Advocates asserts that SCE has failed to demonstrate that these pilot projects will solve problems unique to SCE. Below, we segment each of the pilots out into different discussions and outcomes.

First, with respect to the Smart City Pilot Project, the Commission has already made funds accessible to establish microgrids through an array of Commission microgrid decisions, including the Microgrid Incentive Program.[812] Thus, we agree with Cal Advocates that SCE has not met its burden to demonstrate that this pilot project is needed given the existing funding that already exists for microgrid pilots. Approving the Smart City Pilot Program

[812] D.23-03-034, Ordering Paragraph 8.

would be duplicative of prior Commission efforts at a time when rates are increasing. We decline to adopt the Smart City Pilot Program.

Second, with respect to the Virtual Programmable Automation Controller Pilot Project, we authorize and adopt this program. This pilot would establish the SCE standards for the use of a Virtual Programmable Automation Controller in substation automation in an effort to reduce the overall cost and schedule requirements of this integration rather than having to do a unique design for each individual project. We find these activities reasonable. Thus, we authorize and adopt this program and its 2025-2028 forecast of $3.940 million.

Third, with respect to the Virtual Protection Pilot Project and Adaptive Protection pilots, we decline to authorize and adopt these programs. SCE has not demonstrated that these projects will provide a benefit to ratepayers that meet or exceed the cost of these pilots. The purpose and benefits of these programs — to accommodate the expected influx of DERs — is duplicative of efforts the Commission is authorizing in this GRC to meet the demand that DERs may present to the grid. Thus, we decline to adopt and authorize these programs.

Next, with respect to the DC Link pilot, we authorize and adopt this program and SCE's 2025-2028 forecast of $14.607 million. This pilot project brings value to the SCE grid because it will implement one or more battery energy storage systems capable of connecting to two adjacent circuits (*i.e.*, DC Link). This connectivity will facilitate achieving greater economies of scale for distribution connected storage capacity by allowing one system to be sized to the interconnection capacity of two adjacent circuits. The DC Link will also enable SCE to move load from a heavily loaded circuit to a lightly loaded circuit, thereby increasing utilization and cost effectiveness of the distribution system.

Thus, SCE has demonstrated the reasonableness of this capital forecast. We authorize and adopt SCE's 2025-2028 forecast of $14.607 million.

Finally, with respect to the Service Center of the Future, we authorize and adopt this pilot project and its 2025-2028 forecast of $7.111 million. This pilot project is reasonable because it will enable SCE to develop a new standard for providing service to large transportation load centers, which are emerging as transportation electrification moves toward alignment with California's goals. This pilot will enable SCE to establish standards to support both load-side operational needs and grid-side operational infrastructure constraints. Therefore, we authorize and adopt this pilot project.

11.3.1.5. Energy Storage O&M

Again, we have two questions presented before us. The first question is whether the Commission should adopt and authorize the Energy Storage O&M and if so, what the authorized funding should be.

SCE requests a total TY 2025 O&M forecast for Energy Storage at $12.360 million. This forecast covers three activities: (1) $1.679 million for the Distribution Energy Storage Integration activity (DESI); (2) $0.150 million for the Long Duration Energy Storage (LDES) activity; and (3) $10.531 million for Generation (*i.e.*, the Mira Loma and RUOES sites). Cal Advocates opposes these forecasts. We find that SCE has shown that these forecasts are reasonable, particularly in order to maintain the reliability sites and in light of the 2021 gubernatorial reliability proclamation.[813] Therefore, we authorize and adopt the $12.360 million TY 2025 O&M forecast for Energy Storage.

[813] Governor's July 30, 2021 Proclamation of a State of Emergency pertinent to potential 2022 grid reliability issues. *See* SCE OB at 102.

11.3.1.6. Energy Storage Capital

Finally, the question presented before the Commission is whether SCE's 2023-2025 forecast of $39.177 million in capital expenditures for Energy Storage should be adopted. These capital expenditures are associated with both DESI ($29.981 million) and LDES ($9.196 million).

We authorize and adopt SCE's forecast of $39.177 million in capital expenditures for Energy Storage. SCE revised its DESI forecast to account for expenditures to support capital upgrades for three operational systems and the project close out of six additional systems.[814] We find that these activities and expenditures are reasonable.

Next, with respect to the LDES capital request of $9.196 million, we find this forecast reasonable and authorize and adopt this capital request. SCE has demonstrated the benefits of the LDES project, which include: (1) acceleration of the commercialization of non-lithium-ion energy storage technologies, which can facilitate high renewables integration by acting as base generation replacement; (2) increased flexibility and more reliability in the event of extreme conditions such as occurred in the August 2020 power emergencies; and (3) potential for commercialization of non-lithium-ion energy storage technologies which could lead to greater flexibility, reliability, performance, and cost optimization. However, we agree with TURN that SCE should submit annual progress reports that summarize the status of the project, funds expended, and lessons learned.[815]

Therefore, we direct SCE to annually file a Tier 1 advice letter to the Commission's Energy Division, on December 31 of each year for the TY period,

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[814] SCE OB at 107.

[815] Ex. TURN-06 at 8-9.

that summarizes: (1) the status of the project(s); (2) funds expended; (3) expected or realized benefits; and (4) lessons learned.

In conclusion, we authorize and adopt the $9.196 million 2025 TY LDES forecast for Energy Storage Capital.

11.3.2. Uncontested Programs

No party contested the following 2023-2025 programs and forecasts: (1) Engineering and Planning Software Tools at $81.641 million; (2) Grid Management System at $131.357 million; (3) Communications at $255.748 million; and (4) DER Hosting Capacity Reinforcement at $2.253 million. Therefore, we find these programs and forecasts reasonable. We authorize and adopt these programs and their respective forecasted amounts.

12. Load Growth, Transmission Projects, and Engineering

12.1. Load Growth

12.1.1. Load Growth, Base Forecast, TEGR, and the 2026 World Cup and 2028 Summer Olympics

In its application and testimony, SCE states it is facing the largest, most rapid growth in demand for electricity in decades. SCE argues that long lead times for construction of critical facilities, like new substations, and customer demand to meet California's electrified future, are imminently needed to support future load growth. SCE asserts that customers will be more likely to embrace electrification solutions necessary to meet the state's greenhouse gas reduction objectives when they have confidence that the grid can meet their electrification reliability demands.[816]

[816] Application at 4.

To meet these demands, SCE presents a Load Growth Forecast. SCE requests that the Commission approve its request for $920.811 million. Below, we segment the expenditures into specific revenue streams that comprise SCE's $920.811 million request:

- $200.041 million: 2023-2025 capital expenditure forecast for SCE's Transportation Electrification Grid Readiness (TEGR) Load Growth Forecast, which includes all of SCE's proposed TEGR projects;[817]
- $544.600 million: 2023-2025 capital expenditure forecast for SCE's Base Load Growth Forecast, which includes all of SCE's proposed projects under its base load growth forecast for its Distribution Substation Plan (DSP) and Transmission Substation Plan (TSP), except for DSP DERs;[818] and
- (3) $176.170 million: 2023-2025 capital expenditure forecast for SCE's Other Load Growth Capital Expenditures Forecast, which includes SCE's forecasts for System Improvement Programs ($140.995 million), DSP DERs ($12.537 million), Climate Driven Distribution Circuit Ties ($19.742 million) and Land Rights Management ($2.896 million).[819]

Load Growth Forecast and TEGR: In its testimony, SCE explains its reasoning to support its requests. First, SCE begins its load growth forecast analysis through the development of a 10-year load growth forecast at the distribution circuit level.[820] From the distribution circuit level, SCE then bases its load growth forecast through the disaggregation of the California Energy

[817] Ex. SCE-13, Vol. 7 at 9, Table II-7.

[818] Ex. SCE-13, Vol. 7 at 63, Table II-11.

[819] Ex. SCE-13, Vol. 7 Table II-13 at 82, Table II-15 at 88, Table II-16 at 94, and Table II-6 at 7.

[820] Ex. SCE-02, Vol. 7 at 17.

Commission's (CEC's) 2020 Integrated Energy Policy Report (IEPR) load growth forecast. 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, and distributed generation such as solar photovoltaic systems.[821] SCE utilizes the IEPR forecast for these load-modifying inputs and disaggregates them into the distribution circuit level.[822] SCE states that the 2020 IEPR forecast did not capture an accurate view of grid planning needs to support the state's transportation electrification goals and targets.[823] As a consequence, SCE developed the TEGR to account for CARB's transportation electrification policies, leveraging assumptions in CARB's 2020 Mobile Source Strategy, as well as the CEC's Assembly Bill (AB) 2127 EV Charging Infrastructure Assessment.[824]

For both peak load and high DER output scenarios, SCE developed a 10-year load growth forecast at the distribution circuit level using the IEPR load growth forecast.[825] SCE also performed technical studies to determine whether the projected forecasts can be accommodated by SCE's existing electric grid based on equipment loading limits.[826] When studies show that peak load or DER impacts are expected to exceed planned loading limits, SCE identified potential solutions to mitigate the risk of overloading equipment.[827] In addition to

[821] Ex. SCE-02, Vol. 7 at 17.

[822] Ex. SCE-02, Vol. 7 at 18.

[823] Ex. SCE-02, Vol. 7 at 17.

[824] Ex. SCE-02, Vol. 7 at 19-20.

[825] Ex. SCE-02, Vol. 7 at 24.

[826] Ex. SCE-02, Vol. 7 at 22-24.

[827] Ex. SCE-02, Vol. 7 at 67.

distribution circuit upgrade projects, SCE states system improvements may also arise due to local reasons, including: (1) changes in load profiles that drive localized voltage problems; (2) instances where new protection devices and switches are needed for safety and reliability; or (3) new residential developments.[828]

In support of its load growth forecast, SCE makes an array of arguments. First, SCE states that the TEGR is necessary because its Base Forecast does not account for California's policies and goals that promote transportation electrification or for SCE's bottom-up analysis of localized customer propensity for electric vehicle adoption.[829] Second, SCE states that if its TEGR Forecast is not adopted, its ability to timely energize customers will be hindered, contrary to Senate Bill (SB) 410 (Stats. 2023, ch. 394).[830] Third, SCE states that California's decarbonization policies will not be served if California waits for complete certainty before investing in the grid.[831] Fourth, SCE states that its TEGR methodology and assumptions are reasonable and supported.[832] And finally, SCE argues that its TEGR is likely a conservative estimate and, most likely, underestimated.[833]

Base Load Growth Forecast: With respect to its Base Load Growth Forecast, SCE states it creates this forecast through the disaggregation of the 2020 IEPR forecast. SCE's disaggregation methodology of the IEPR forecast

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[828] Ex. SCE-02, Vol. 7 at 39.

[829] SCE OB at 112.

[830] SCE OB at 116.

[831] SCE OB at 119.

[832] SCE OB at 122.

[833] SCE OB at 130.

encompasses specific local-area knowledge from its system planning engineers on developers' new projects, as well as economic data relative to each planning area.[834] For 2023-2025, SCE forecasts $544.600 million for its DSP and TSP base load growth forecast.[835]

Other Load Growth Expenditures: In support of its Other Load Growth Capital Expenditure Forecasts, SCE forecasts $176170 million. This forecast includes System Improvement Programs ($140.995 million), DSP DERs ($12.537 million), Climate Driven Distribution Circuit Ties ($19.742 million), and Land Rights Management ($2.896 million). System Improvement Programs encompass Distribution Plant Betterment, New Capacitors, Distribution Volt-Volt Amp Reactive (Volt Amp Reactive) Control and Programmable Capacitor Controller Replacement Program, and Substation Equipment Replacement Program.[836]

2026 World Cup and 2028 Summer Olympics: Finally, SCE requests Commission authorization to establish a Historic Sporting Events Cost Tracking Memorandum Account (HSECTMA) for the 2026 World Cup and 2028 Olympics. SCE also requests authorization to establish a DER-Driven Grid Reinforcement Program Memorandum Account (DER-DGRPMA).

12.1.2. Parties' Positions

An array of intervenors supported or opposed SCE's Load Growth forecasts. Cal Advocates, Joint Ratepayers, SBUA, and TURN oppose all or some elements of SCE's Load Growth Forecast. CUE, Joint Truck OEMs, NRDC,

[834] Ex. SCE-02, Vol. 7 at 17.

[835] Ex. SCE-13, Vol. 7 at 63.

[836] Ex. SCE-13, Vol. 7 at 82.

Terawatt, Tesla, and Walmart support all or some of SCE's Load Growth Forecast. Of these intervenors, Cal Advocates and TURN have made specific arguments and proposals that adjust down SCE's Load Growth expenditure request. We present the intervenors' positions on SCE's forecast, below.

12.1.2.1. TURN

TURN opposes all costs associated with the TEGR. TURN recommends the Commission adopt its proposed reduction of $259.860 million in capital expenditures from SCE's load growth recommendation over the 2023-2025 period, including a reduction of $205.551 million in the 2025 TY.[837] TURN asserts that SCE's TEGR plan is flawed because it is based on assumptions that have not materialized in the past few years and conflict with the CEC's updated IEPR vintages.[838] TURN argues that SCE has not demonstrated the reasonableness of its TEGR project costs, and the Commission should not accept that new sources of demand for electricity equate to higher capital infrastructure costs.[839] TURN states there are significant locational and technical uncertainties associated with load forecasting for new technology groups such as medium- and heavy-duty electric vehicles. Thus, TURN asserts that risk in poor infrastructure investments will inequitably harm ratepayers and increase retail rates, discouraging adoption of transportation electrification. TURN makes the following additional arguments: (1) SCE's load growth forecast is too high due to erroneous assumptions in the TEGR that inflate anticipated demand;[840] (2) other planning

[837] TURN OB at 104-105, 118.

[838] TURN OB at 105.

[839] TURN OB at 104.

[840] Ex. TURN-07E at 23-24.

assumptions in the TEGR are inaccurate;[841] (3) SCE's base forecast is inflated;[842] (4) the TEGR should not be authorized because of misalignment with the 2020 IEPR;[843] and (5) SB 410 provides an alternative funding mechanism in the unlikely event SCE's GRC authorized forecast is insufficient.[844] TURN also suggests that if any capital is approved for TEGR, then it should be in a one-way balancing account with a cap.[845]

Additionally, TURN recommends the Commission authorize a reduction to SCE's Base Load request, in addition to removal of all costs resulting from the TEGR supplemental forecast. This amounts to a reduction of $59.818 million over 2023-2025, including $38.184 million in the Test Year.[846] With respect to the SCE DSP request, TURN recommends the following two reductions: (1) removal of costs associated with the DSP Substation Project PIN 8043; and (2) removal of all costs for DSP DER capital expenditures.[847] For SCE's TSP request, TURN recommends the following reductions: (1) $8.422 million in the Test Year due to the cancellation of a planned A-Bank Substation, TSP A-Bank 35796 (Reactor);[848] and (2) full denial of the costs associated with SCE's new proposed climate-driven circuit ties program.[849]

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[841] Ex. TURN-07E at 14-15, 16-18, and 19-20.

[842] Ex. TURN-08E at 1.

[843] Ex. TURN-07E at 21.

[844] TURN OB at 120.

[845] TURN RB at 33.

[846] TURN OB at 127.

[847] TURN OB at 128-129.

[848] TURN OB at 132.

[849] TURN OB at 133.

With respect to the DSP Plan, TURN recommends that DSP Substation Project PIN 8043 and the costs associated with this project, which total $9.830 million over the 2023-2028 period, be removed. TURN argues that this project was previously authorized funding in the 2021 GRC to meet an in-service date of November 2021.[850] TURN asserts that there must be a limitation on duplicative authorization for the same capital expenditures in subsequent rate cases.[851]

12.1.2.2. Cal Advocates

Like TURN, Cal Advocates makes an array of arguments in support of the significant, across-the-board reductions it recommends the Commission adopt. Particularly, Cal Advocates argues that SCE has not established that it is entitled to any funding for TEGR load growth capital.[852]

First, Cal Advocates argues that SCE's electric vehicle forecast is aggressive in the near term because SCE's forecasts are higher than the 2022 IEPR's forecasts.[853] Second, Cal Advocates argues that SCE is frontloading capital investments for electric vehicles. Cal Advocates asserts that electric vehicle adoption rates, charging locations, and charging times are uncertain. Cal Advocates states that there is significant risk to overestimating the influx of electric vehicles and the corresponding infrastructure needs, which leads to increased costs.[854] Similarly, Cal Advocates argues that SCE's internal load shapes may be overestimating peak load associated with electric vehicles. For

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[850] Ex. TURN-07 at 28.

[851] TURN OB at 129.

[852] Cal Advocates OB at 137; *see also* Ex. CA-08E at 8.

[853] Ex. CA-08E at 19.

[854] Cal Advocates OB at 151.

example, Cal Advocates argues that SCE did not include full time-of-use responsiveness in its load shapes by considering its super off-peak period for commercial customers between 8:00 a.m.-4:00 p.m. and the data supporting that customers enrolled in these time-of-use rates are actively shifting their usage to mid-day.[855] Thus, Cal Advocates argues for significant reductions. Cal Advocates recommends the Commission disallow all TEGR capital expenditures.[856]

With respect to SCE's Baseline Forecast, Cal Advocates recommends downward adjustments. Cal Advocates' total capital expenditure recommendations for the Baseline Forecast Load Growth capital expenditures are: (1) $96.8 million (2023); (2) $143.6 million (2024); (3) $165.8 million (2025); (4) $286.9 million (2026); (5) $265.2 million (2027); and (6) $215.4 million (2028). Finally, for the DSP, TSP, and System Improvement Programs, Cal Advocates recommends the following: (1) $35.2 million for DSP DERs; (2) $214.4 million for DSP New Circuits; (3) $201.7 million for DSP Circuit Upgrades; (4) $374.9 million for DSP Substations; (5) $74.8 million for TSP Subtransmission Lines Plan; (6) $1.8 million for TSP A-Bank Plan; (7) $5.77 million for the TSP Subtransmission; and (8) $214.3 million for the System Improvement Programs.[857]

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[855] Cal Advocates OB at 155.

[856] Cal Advocates OB at 138; s*ee also* Ex. CA-08E at 8.

[857] Ex. CA-08 at 8.

For the DSP Base plan, Cal Advocates recommends a downward adjustment of $1.9 million in 2023 to remove a line purchased in 2023 for DSP Substations. Cal Advocates argues that SCE did not justify this purchase.[858]

12.1.2.3. SBUA

SBUA recommends that the Commission deny SCE's TEGR request and establish a memorandum account for SCE spending on TEGR beyond the base level.[859] SBUA asserts that this approach balances the need to proactively address the significant peak load changes that accompany building electrification, DER expansion, and transportation electrification growth.

12.1.2.4. Joint Ratepayers

The Joint Ratepayers argue that SCE does not establish that the TEGR capital expenditure request is reasonable. TURN, Cal Advocates, and Joint Ratepayers assert that there are flaws in SCE's inputs and assumptions underlying the TEGR methodology which inflate electric vehicle forecasts and the significant locational and technical uncertainties surrounding transportation electrification load growth.[860] Furthermore, Joint Ratepayers argue that the TEGR would result in many current businesses having to shut down or leave the state before any purported benefits materialize in 2032.[861] Joint Ratepayers state that SCE's load growth capital expenditures are unreasonable given the uncertainty in the Test Year surrounding electric load growth and electric vehicle adoption.[862] Thus, Joint Ratepayers recommend the Commission require SCE to

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[858] Ex. CA-7 at 14.

[859] SBUA RB at 5.

[860] Joint Ratepayers OB at 30-32.

[861] Ex. Joint Ratepayers-01 at 21.

[862] Ex. Joint Ratepayers-01 at 2-3.

use lower and more realistic load growth forecasting inputs or, alternatively, disallow the full amount of capital expenditures associated with the TEGR.[863]

12.1.2.5. NRDC

NRDC supports SCE's Load Growth forecast, and supports the TEGR.[864] NRDC asserts that SCE's TEGR is compliant with California's electrification and decarbonization laws. NRDC states that SCE is required by the state to take into account policies and regulations requiring transportation electrification and, because the 2020 IEPR did not take those policies and regulations into account, SCE needed to look to alternative forecasts for compliance.[865] NRDC argues that SCE must propose grid upgrades in the GRC to comply with California policy to fully electrify light, medium, and heavy-duty vehicles, and buildings through 2045.[866] NRDC states that upgrades are likely needed due to baseline load growth alone, even if transportation electrification and building electrification are removed from load growth forecasts.[867] NRDC further asserts that SCE's load growth and grid upgrade need projections do not suggest overbuilding but rather, what is required to meet anticipated load and facilitate the fulfillment of California's climate laws.[868] Like Walmart, NRDC states that SCE's TEGR forecast and revenue request are not only reasonable but may understate needed grid upgrades and associated revenue.[869] NRDC further reasons that delaying

[863] Joint Ratepayers OB at 36.

[864] NRDC OB at 11.

[865] NRDC OB at 12.

[866] Ex. NRDC-01 at 4.

[867] Ex. NRDC-03 at 19.

[868] NRDC OB at 15.

[869] NRDC OB at 15.

investment and making too few grid upgrades in the near term risks economic loss for SCE's customers because of unmet customer need.[870] Thus, NRDC recommends that the Commission establish a two-way balancing account for funds authorized to support energization of load-growth-related infrastructure to ensure SCE has enough funds to make necessary grid upgrades while also ensuring ratepayer funds will be reimbursed if less capital is ultimately required.[871]

12.1.2.6. Walmart

Walmart asserts that SCE has not included enough capacity to fully support the state's transportation electrification projections. Walmart states that given the consumer electric vehicle sales and electric vehicle fleet deployment growth in SCE's region, SCE's forecasted TEGR capital expenditures are likely too low. Walmart asserts that the Commission should ensure sufficient funding for new electric vehicle charging deployments. Alternatively, Walmart states that if the Commission disallows SCE's TEGR capital expenditures, then the Commission should approve an SB 410 mechanism for capital expenditure recovery.[872] Under this proposal, Walmart recommends that SCE invest no more than the amount resulting in a rate impact in any year during the test period of no more than 2.5 percent of the 2028 electric distribution revenue requirement ultimately approved by the Commission.[873]

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[870] Ex. NRDC-03 at 9.

[871] Ex. NRDC-03 at 10.

[872] Walmart OB at 8.

[873] Ex. WMT-01 at 17.

12.1.2.7. Terawatt

Terawatt asserts that SCE's TEGR forecast does not go far enough. First, Terawatt asserts that SCE's load growth forecast does not consider policies and incentives that further increase demand for medium- and heavy-duty electric vehicle adoption that were enacted since the development of the TEGR.[874] Second, Terawatt argues that SCE makes unrealistic assumptions about the ability of fleets to engage in managed charging, which has the impact of greatly underestimating likely transportation electrification load growth and the impact on SCE's distribution and sub-transmission systems. Terawatt recommends the Commission reject Cal Advocates' arguments that the TEGR projects are premature because of a lack of current medium- and heavy-duty electric vehicle adoption.[875]

12.1.2.8. Tesla

Tesla supports SCE's TEGR. Tesla argues that SCE's TEGR provides a reasonable basis for expected infrastructure need. Tesla states that the use of the IEPR load growth forecast for infrastructure planning is problematic because of the significant lag time between when the IEPR forecast is generated and when the DPP or GRC are informed by that IEPR vintage.[876] Tesla reasons that this lag has created major issues for grid planning during the early years of the 2020s when California transitioned from flat load growth to significant load growth driven by a combination of consumer demand for electric vehicles and the state's newly enacted transportation electrification policies.[877]

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[874] Terawatt OB at 11.

[875] Terawatt OB at 12.

[876] Tesla OB at 6.

[877] Tesla OB at 6.

Tesla recommends that the Commission approve SCE's request for capital expenditures to support transportation electrification because its request is based on a reasonable forecast for transportation electrification load growth and properly includes long-lead time investments to plan for electric vehicle adoption beyond the GRC window.[878] Tesla also recommends that the Commission reject Cal Advocates' and TURN's recommendations because their analysis overlooks the fact that many of SCE's TEGR investments require spending in this GRC period to have in-service dates after 2028.[879] Tesla reasons that the TEGR aligns with the approach needed to meet the state's electrification laws, regulations, and goals. Finally, Tesla supports SCE's load growth forecast because it aligns with the CEC's most recent forecasts of light, medium-, and heavy-duty electric vehicle adoption and it uses that load forecast to create a bottom-up predication of the locations where distribution system constraints are likely to arise so that capacity can be added in advance of energization requests.[880]

12.1.2.9. Joint Truck OEMs

The Joint Truck OEMs also support SCE's TEGR forecast. The Joint Truck OEMs argue that SCE's TEGR forecast is reasonable in response to new regulations and other developments that occurred after SCE's base forecast was set.[881] The Joint Truck OEMs assert that the Commission's approval of SCE's request to upgrade the grid in support of charging electric medium- and heavy-duty vehicles is critical to ensuring that SCE has sufficient grid capacity to

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[878] Tesla OB at 9-12.

[879] Tesla OB at 11.

[880] Tesla OB at 3.

[881] Joint OEMs OB at 7.

support the charging stations needed to fuel the deployment of medium- and heavy-duty commercial zero emission vehicles.[882] The Joint Truck OEMs contend that delays in energization due to requests for service requiring grid upgrades exceed the charging infrastructure developer's timeline for service need.[883] The Joint Truck OEMs also contend that potential customers will not invest in electric medium- and heavy-duty vehicles unless they are confident they can charge vehicles easily and efficiently.[884] The Joint Truck OEMs state the charging facilities for medium- and heavy-duty vehicles that existed in 2023 were not adequate to meet growing demand because other proposed charging stations could not be connected due to insufficient capacity on the SCE grid.[885]

Additionally, the Joint Truck OEMs state that TURN and Cal Advocates are incorrect that vehicle fleets would charge during the 8:00 a.m. to 4:00 p.m. super off-peak hours because that is when they perform their critical business functions.[886]

12.1.2.10. CUE

CUE supports SCE's TEGR load forecast. CUE asserts the TEGR model integrates detailed historical data, bottom-up analyses and data specific to SCE's service territory to predict future load growth as accurately as possible.[887] CUE also notes that most components of SCE's grid are near their capacity limits which means that additional load, especially from transportation electrification,

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[882] Ex. Joint Truck OEMs-01 at 7.

[883] Ex. Joint Truck OEMs-01 at 7-9.

[884] Joint Truck OEMs OB at 8.

[885] Joint Truck OEMs OB at 8-9.

[886] Joint Truck OEMs OB at 11-12.

[887] CUE OB at 40.

will likely trigger grid upgrades. CUE asserts that there is hardly a place on SCE's grid that will not soon require upgrading.[888] CUE recommends the Commission authorize SCE's load growth forecast and collect this funding in a two-way balancing account as a ratepayer protection.[889] CUE reasons that this approach will ensure SCE is prepared to facilitate electrification on a timeline consistent with state and federal law while ensuring funding is spent to support load growth or returned to ratepayers.[890]

12.1.2.11. SCE's Rebuttal

In response to TURN, Cal Advocates, and the Joint Ratepayers, SCE argues the following: (1) TEGR is supported by state and Commission policy;[891] and (2) TEGR's methodology and assumptions are reasonable.[892]

SCE states that TURN's and Joint Ratepayers' recommendation to authorize $0 for TEGR and take a "wait and see" approach with respect to the acceleration of electrification-driven load growth is contrary to state and Commission policy. SCE asserts that TURN's and Joint Ratepayers' approach would unnecessarily delay investments that need to start now.[893] Next, SCE argues the Commission should not accept TURN's contention that it is permissible to underfund SCE for electrification-driven load growth in this GRC because SCE can come back in the future to try and recover the shortfall in funding through an SB 410 ratemaking mechanism. In support of this

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[888] CUE OB at 41.

[889] CUE OB at 42.

[890] CUE OB at 43.

[891] SCE OB at 110-112.

[892] SCE OB at 122.

[893] SCE RB at 40.

contention, SCE reasons that SB 410 is not a reason to delay necessary funding for transportation electrification growth and would run afoul of the bill's purpose.[894] SCE states that denying TEGR and giving SCE nothing for electrification-driven load growth in this GRC thus may create a shortfall that is too large for SCE to be made whole through an SB 410 ratemaking mechanism.[895]

Next, in response to TURN and Cal Advocates regarding its base load growth forecast, SCE makes an array of rebuttal arguments. First, SCE states that Cal Advocates' reductions to its base load growth are unreasonable and unsupported.[896] SCE argues that Cal Advocates' system level alignment methodology is fundamentally flawed and contrary to the reality of grid planning.[897] Second, SCE argues that TURN's and Cal Advocates' DSP and TSP project-specific recommendations are unreasonable and should be rejected.[898] Third, SCE rejects Cal Advocates' and TURN's System Improvement Program reductions because they are unreasonable and inappropriate.[899]

Finally, SCE requests Commission authorization to establish the HSECTMA and the DER-DGRPMA. SCE states that it was not able to estimate the costs for the 2026 World Cup and 2028 Olympics with reasonable certainty when SCE developed its GRC forecast.[900] TURN and Cal Advocates oppose the

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[894] SCE RB at 41.

[895] SCE RB at 42.

[896] SCE OB at 132.

[897] SCE OB at 133; *see also* Ex. SCE-13, Vol. 7 at 67-68.

[898] SCE OB at 133-135.

[899] SCE OB at 138.

[900] SCE RB at 143.

HSECTMA and TURN opposes the DER-DGRMPA. SCE opposes the other ratemaking proposals presented by NRDC, Tesla, and TURN.[901]

12.1.3. Discussion

TEGR: We begin our discussion with the TEGR supplemental forecast. SCE's load growth forecast is primarily predicated upon the results of its TEGR model. The TEGR model is SCE's guide for infrastructure investment to account for grid readiness for future transportation electrification demand.

SCE developed TEGR to augment information in the CEC's 2020 IEPR. SCE asserts that the CEC's load assessment for transportation electrification in the 2020 IEPR forecast used a methodology that does not incorporate recent policies, policies in development, or future anticipated policies. SCE states that as a result of this approach, the forecast rates of electric vehicle adoption in the 2020 IEPR do not align with achieving the state's goals and targets, which, in turn, impacts SCE's grid planning. As a consequence, SCE developed TEGR to supplement the 2020 IEPR forecast with a progressive view of grid planning needs to achieve California's goals and targets.[902] Indeed, California has adopted numerous laws and policies driving electrification across the state and locally, in SCE's service territory, in commitment to achieving carbon neutrality by 2045.

California's electrification laws and policies trigger regulatory action aimed to support California's decarbonization goals, with a focus on electrifying the building and transportation sectors.[903] For example, the California Legislature recently passed two laws, SB 410 and AB 2700 (Stats. 2022, ch. 354),

[901] SCE RB at 143-145.

[902] Ex. SCE-02, Vol. 7 at 19.

[903] Ex. NRDC-01E at 1.

which require California's electrical corporations to proactively facilitate electrification consistent with state and federal legal requirements. AB 2700 amended Pub. Util. Code Section 740.21 to require California's electrical corporations to:

> [F]acilitate the readiness of their distribution systems to support the level of electric vehicle charging anticipated in its service territory by Executive Orders No. B-48-18 and N-79-20, the Energy Commission's integrated energy policy report adopted pursuant to Section 25302 of the Public Resources Code, the Energy Commission's assessment prepared pursuant to Section 25229 of the Public Resources Code, State Air Resources Board regulations, air quality management plans, regional seaport plans, regional transportation plans, and sustainable communities strategies.[904]

Additionally, Section 740.21 requires California electrical corporations to explain how investment proposals in their GRC applications are consistent with California's regulatory scheme and laws.[905] Meanwhile, SB 410 amended Section 833 to require the electrical corporations to upgrade the state's electrical distribution systems, as needed, in time to achieve the state's decarbonization goals.[906] Finally, the Legislature authorized SCE to consider forecasts that exceed those in the IEPR.[907]

Considering the above, alongside the positions of the intervenors, we authorize and adopt SCE's TEGR model, but reduce SCE's revenue request for the TEGR by 50 percent for an authorized amount of $100.021 million. We

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[904] Pub. Util. Code Section 740.21(a).

[905] Pub. Util. Code Section 740.21(b).

[906] Pub. Util. Code Section 933(c).

[907] Pub. Util. Code Section 936(a)(1)(E).

reduce SCE's revenue request because of uncertain market conditions. We order SCE to file an annual Tier 1 advice letter, filed with the Commission's Energy Division, reporting on its capital expenditures for projects identified through its TEGR forecast every March 1st through the GRC Period, with the final report due March 1, 2029. In the Advice letter for TEGR expenditures, SCE shall provide: (a) the project name; (b) project number (consistent with SCE's testimony); (c) description and project scope, location, status, the current planned operating date; (d) the forecasted operating date in the 2025 GRC; and (e) capital expenditures by year and to date, and forecasted cost in the 2025 GRC. SCE shall also report in this advice letter if: (a) energization request(s) are dependent on the project's completion; (b) how much the expected hosting capacity on the substation and its circuits are expected to increase; and (c) what customer types are anticipated to benefit from the project (*e.g.*, LD public charging, MDHD public charging, port customers, *etc.*).

Finally, SCE is authorized to establish a memorandum account to track and record any capital expenditures above the authorized amounts authorized in this Decision to support SCE's grid readiness for future transportation electrification demand. SCE may file a Tier 1 advice letter to establish this memorandum account to track and record capital costs above the authorized amounts for reasonableness review. Should SCE pursue this, SCE should file an application for after-the-fact reasonableness review, and it and may request an expedited schedule to review its request pursuant to Rule 2.9.

Base Forecast: Next, we address SCE's Base Load Growth Forecast. SCE's base load growth forecast is established through the disaggregation of the CEC's 2020 IEPR load growth 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.[908] For 2023-2025, SCE forecasts $544.600 million for its DSP and TSP base load growth forecast.

For its part, Cal Advocates recommends an adjustment of SCE's base forecast to align with the 2022 IEPR. To do this, Cal Advocates recommends an alignment methodology where it derived a ratio of the difference between SCE's forecast peak load growth and the 2022 IEPR's forecast peak load growth at the system level, both relative to the five-year average historical peak load at the system level.[909] SCE opposes Cal Advocates' proposed reductions and to the base forecast and methodology. SCE asserts that Cal Advocates' positions are unreasonable because: (1) Cal Advocates' alignment methodology is unsupported and contrary to the reality of grid planning; and (2) applying an annual percentage reduction to SCE's proposed investments is inappropriate.[910] SCE has demonstrated that its base forecast is reasonable. We decline to adopt the adjustments Cal Advocates recommends. TURN recommends removing the forecast for PIN TSP A-Bank 35796 since SCE has determined it no longer needs this project. We agree with TURN that this project should be taken out of the Base forecast, and that the Base forecast should be lowered by $0 million in 2023, $4.090 million in 2024, and $8.442 million in 2025. Therefore, we find that SCE's 2023-2025 $532.068 million capital expenditures forecast for Base Load Growth, which encompasses all of SCE's DSP and TSP projects, is reasonable. We discuss

[908] Ex. SCE-13, Vol. 7 at 63-64.

[909] Cal Advocates OB at 165-166.

[910] SCE OB at 131-134.

our reasoning for the DSP and TSP projects that were in contention among the parties, below.

DSP and TSP: In short, the DSP and the TSP are results of a coordinated process that begins the disaggregation of the CEC's IEPR load growth forecast, the Distribution Forecasting Working Group, and SCE's analysis of load growth that may not have been fully reflected in the CEC's IEPR forecast.[911] The outcome of this process is a set of proposals from SCE for the DSP and sub-transmission needs for the TSP.

For the DSP Base plan, Cal Advocates recommends a downward adjustment of $1.9 million in 2023 to remove a line purchased in 2023 for DSP Substations.[912] Cal Advocates argues that SCE did not justify this purchase. TURN recommends that DSP Substation Project PIN 8043 and the costs associated with this project, which total $9.830 million over the 2023-2028 period, be removed. TURN argues that this project was previously authorized in the 2021 GRC to meet an in-service date of November 2021.[913] TURN asserts that there must be a limitation on duplicative authorization for the same capital expenditures in subsequent rate cases.[914]

In response to Cal Advocates, SCE states that the line in contention was in the original RO Model shared with Cal Advocates along with SCE's direct testimony and it was included in a standard capital workpapers alongside SCE's direct testimony.[915] SCE also states that it ultimately recorded $3.4 million for

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[911] Ex. SCE-13, Vol. 7 at 63-64.

[912] Ex. CA-7 at 14.

[913] Ex. TURN-07 at 28.

[914] TURN OB at 129.

[915] Ex. SCE-13, Vol. 7 at 73.

this project in 2023 and the asset went into service on October 21, 2023.[916] SCE argues that it is not reasonable to disallow these actually incurred costs for an asset that is used and is useful. We agree. SCE has demonstrated that this cost is reasonable and has provided adequate justification. We adopt this cost.

With respect to TURN, SCE states it has justified that the delay in this project was reasonable and outside of SCE's control.[917] SCE states that work on this project is still needed during this GRC cycle and that the record shows that SCE experienced delays associated with additional civil and electrical work that were not originally part of SCE's 2021 GRC submission.[918] Indeed, the record does show that the delays were outside of SCE's control and that the capital expenditures are necessary to support the increased capacity of the Garnet 115/33 kV Substation. SCE has demonstrated that this cost is reasonable and has provided an adequate justification for the delays associated with the project. We adopt this cost.

Next we evaluate SCE's TSP. The TSP consists of the Subtransmission Lines Plan, the A-Bank Plan, and the Subtransmission VAR Plan. The Subtransmission Lines Plan focuses on SCE's 66 kV and 115 kV subtransmission lines to ensure safe and reliable service to customers.[919] SCE states that 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 its service territory.[920] The Subtransmission Lines

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[916] Ex. SCE-13, Vol. 7 at 74.

[917] SCE OB at 135.

[918] SCE OB at 136.

[919] Ex. SCE-02, Vol. 7 at 70-71.

[920] Ex. SCE-02, Vol. 7 at 73.

Plan includes the following four different types of projects: (1) Loop-In or Line Modification Projects; (2) Reconductoring and Recabling Projects; (3) New Line Projects; and (4) Voltage Driven Projects.[921] For the Subtransmission Lines Plan, SCE forecasts $145.9 million for years 2023-2028 which would be allocated for 16 projects.[922]

The SCE A-Bank Plan consists of providing adequate capacity at each transmission substation to serve forecast peak loads under normal conditions.[923] These forecast loads represent the maximum demand for the highest expected temperature within a five-year period, referred to as a one-in-five (1-in-5) year heat storm condition. When SCE forecasts that an A-Bank transformer will become overloaded within the 10-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.[924] If this cannot be achieved, a project to expand, upgrade, or reinforce SCE's system is initiated.[925] SCE states that it has identified four A-Bank projects with capital expenditures totaling $430.438 million for years 2023-2028.[926] As previously noted, TURN recommends removing the forecast for PIN TSP A-Bank 35796 since SCE has determined it no longer needs this project. TURN also contends that, although SCE suggests that additional projects may be needed in its place, it

[921] Ex. SCE-02, Vol. 7 at 73-76.

[922] Ex. SCE-02, Vol. 7 at 76-77.

[923] Ex. SCE-02, Vol. 7 at 79.

[924] Ex. SCE-02, Vol. 7 at 79.

[925] Ex. SCE-02, Vol. 7 at 79-80.

[926] Ex. SCE-02, Vol. 7, at 81.

has not determined the scope, timing, or costs of these alternative proposals.[927] We agree with TURN that this project should not be included in this forecast and that SCE has not justified the continued inclusion of these costs.

The Subtransmission VAR Plan focuses on SCE's system reactive power needed to ensure safe and reliable service. Capacitor banks are installed throughout SCE's system to supply needed reactive power and help maintain adequate voltage.[928] SCE has identified five Subtransmission VAR projects with a total cost of $7.145 million for the years 2023 to 2028.[929] Cal Advocates recommends the Commission adopt its reductions to the Subtransmission VAR Plan to $5.77 million from $7.145 million, which is $1.45 million lower than SCE's estimate. SCE has demonstrated that its Subtransmission VAR Plan is reasonable. Without a comprehensive Substation VAR Plan, SCE states it would risk reactive power deficiency on the subtransmission system as the peak demand for electricity continues to increase.[930] Therefore, we adopt its total cost of $7.145 million.

Other Load Growth Capital Expenditures Forecasts: We begin our discussion of SCE's other load growth capital expenditure forecasts with its requests for capital support of its System Improvement Programs. This includes the following:

- **Distribution Plant Betterment Programs:**[931] Besides improvements and projects covered by SCE's Distribution Circuit Upgrades (DCU) program, needs for other

[927] Ex. TURN-07 at 31-32; Ex. SCE-42 at 156.

[928] Ex SCE-02, Vol.7 at 82.

[929] Ex. SCE-02, Vol. 7 at 83.

[930] Ex. SCE-02, Vol. 7 at 82.

[931] Ex. SCE-02, Vol. 7 at 39.

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;

- **Distribution VAR Program:**[932] The objective of the Distribution VAR Program is to fully supply the peak reactive power needs of each of the distribution circuits under normal weather conditions. In other words, 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 pad mounted capacitor bank on the circuit, depending on the circuit configuration;
- **Distribution Volt-VAR Control Programs:**[933] The Distribution Volt VAR Control (DVVC) Program centralizes control of the field and substation capacitors to coordinate and optimize voltage and VARs across all 30 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 service voltage requirements and operating within the local distribution field Programmable Capacitor Controls settings. The DVVC is implemented as a centralized voltage and VAR control scheme through the Distribution Management System and the Energy Management System, which controls the switching of existing capacitors in substations and on distribution circuits;

[932] Ex. SCE-02, Vol. 7 at 39.

[933] Ex. SCE-02, Vol. 7 at 40.

- **Substation Equipment Replacement Program:**[934] The Substation Equipment Replacement Program evaluates the adequacy of substation terminal equipment and system protection equipment, and proposes upgrades when deficiencies are identified. It 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; and
- **DER Driven Breaker Upgrade Programs:**[935] 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 Analysis in this analysis, as opposed to SERP, which only considers fault contribution from generators connected at the transmission and subtransmission voltage levels.

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[934] Ex. SCE-02, Vol. 7 at 40.

[935] Ex. SCE-02, Vol. 7 at 40-41.

Cal Advocates recommends applying its Alignment Methodology to SCE's System Improvement Programs.[936] This would result in applying a yearly percentage reduction to SCE's System Improvement Programs forecasts. We decline to adopt Cal Advocates' Alignment Methodology. SCE has demonstrated that the System Improvement Programs forecasts are separately derived and are not directly based on SCE's base load growth forecast.[937] SCE has demonstrated that the System Improvement Programs are reasonable, and we therefore adopt the 2023-2025 capital expenditure request for SCE's System Improvements in the amount of $140.955 million.

Next, we discuss SCE's capital expenditure forecasts for DSP DERs. SCE requests $10 million in 2025 and $118.437 million for 2023-2028 for capital expenditures and procurement related to DSP DERs.[938] SCE states that this forecast will support capital expenditures to acquire relocatable energy storage units, which will be non-wires solution alternatives for SCE to facilitate interconnections and other work where the wires-based solutions will take longer to implement than the customer's energization timelines permit.[939] For its part, TURN recommends $0 for these relocatable energy storage devices. TURN argues:[940]

> While TURN is generally supportive of temporary and relocatable alternatives to traditional grid investments to meet new load, utilities should make these investments at least cost feasible to ratepayers. Based on cost estimates provided by

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[936] Ex. CA-8 at 42.

[937] Ex. SCE-13, Vol. 7 at 84-86.

[938] Ex. SCE-02, Vol. 7 at 48.

[939] Ex. SCE-13, Vol. 7, at 88 Table II-15.

[940] TURN OB 129-130.

> SCE, renting rather than purchasing would provide a savings to ratepayers if energy storage devices are in use for fewer than four months each year, or continuously over five or fewer years. The utility cannot argue it both ways, as it seems to do in rebuttal. If these devices are short-term, "stop-gap" measures that do not defer traditional wires solutions, then they are strong candidates for leasing or renting. If these devices are long-lasting investments that should provide value to ratepayers for the entirety of their service lives, then SCE should demonstrate that value.

We agree. Furthermore, TURN and Cal Advocates have demonstrated that SCE's requests for these capital resources are unreasonable at this time because SCE has yet to identify locations for future deployment[941] and, in total, this proposed investment will not be cost effective.[942] Thus, we disallow SCE's request for DSP DERs without prejudice. Instead, SCE may file a separate application requesting DSP DERs should it need to do so.

Now, we address SCE's forecast for Climate Driven Distribution Circuit Ties for Reliability. For this request, SCE forecasts $19.742 million in 2025 and $80.037 million through 2028 in expenditures for Climate Driven Distribution Circuit Ties.[943]

In support of this request, SCE turns to its Climate Adaptation Vulnerability Assessment (CAVA) filing. SCE states that its CAVA filing identified areas that are at-risk of flooding and wildfire impacts, and estimated the potential outages for customers from those climate change impacts. SCE states that customers who rely on radial distribution circuits, which have only

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[941] Ex. CA-8 at 8; Ex. CA-7 at 13-14.

[942] Ex. TURN-07 at 29-30.

[943] Ex. SCE-13, Vol. 7 at 94, Table-16.

one power source for a group of customers, 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. Further, SCE states that the CAVA identified the need to construct additional circuit ties to enable the transfer of unaffected equipment to adjacent circuits to maximize the number of customers remaining energized during a wildfire or flood event. Thus, SCE is proposing to construct circuit tie lines, which would enable greater operational flexibility in flood- and fire-impacted areas and thereby reduce power outages or electric service interruptions and increase reliability for customers.[944] SCE's forecast accounts for nine known circuit tie projects as well as an additional four to eight circuit tie projects that were still undergoing technical analysis for scope feasibility at the time.[945]

For its part, Cal Advocates recommends a downward adjustment of this request to $6.3 million in 2025 and a downward adjustment of $28.9 million between 2026-2028. Cal Advocates argues that SCE has not identified the specific locations for the additional circuit tie projects beyond the nine identified projects listed in the GRC.[946] Cal Advocates also contends that SCE did not justify why these additional circuit tie projects are needed.[947] Similarly, TURN states that these projects have not been shown to be cost-effective when its costs are weighed against the benefits for customer reliability.[948] In short, TURN states

[944] Ex. SCE-13, Vol. 7 at 94.

[945] Ex. SCE-13, Vol. 7 at 95.

[946] Ex. CA-7 at 21.

[947] Ex. CA-7 at 22.

[948] Ex. TURN-07 at 34-36.

that it found no value for ratepayer money.[949] We disagree with Cal Advocates and TURN. SCE has demonstrated that the costs associated with the Climate Driven Distribution Circuit Ties are reasonable. We agree with SCE that the Climate Driven Distribution Circuit Ties aim to improve system reliability for customers affected by natural disasters — including those affected by future wildfire and flood events while also providing long-term benefits of operational flexibility and safety. Thus, we adopt SCE's forecast of $19.742 million in 2025 and $80.037 million through 2028.

Finally, no intervenor contested SCE's Land Rights Management 2023-2025 forecast expenditure of $2.896 million. We find this forecast reasonable and adopt SCE's uncontested Land Rights Management forecast.

HSECTMA and DER-DGRPMA: SCE requests approval for the establishment of a HSECTMA to record actually incurred incremental costs for the 2026 World Cup, taking place in June-July 2026, and the 2028 Summer Olympics, taking place in July-August 2028.[950] SCE states it was not able to estimate costs associated with the 2026 World Cup and 2028 Summer Olympics with reasonable certainty at the time SCE developed its GRC forecast.[951]

TURN opposes the establishment of the HSECTMA. TURN argues that ratepayers should not bear the incremental costs associated with addressing the energy needs of the 2026 World Cup and the 2028 Summer Olympics.[952]
Cal Advocates also opposes the establishment of the HSECTMA. Cal Advocates

[949] TURN OB at 134.

[950] Ex. SCE-02, Vol. 7 at 95.

[951] Ex. SCE-13, Vol. 7 at 102; Ex. SCE-02, Vol. 7 at 95.

[952] TURN OB at 417-418.

argues that the Commission should disallow SCE's request for the HSECTMA and direct SCE to submit an application to the Commission that outlines the capital investments needed for the 2026 World Cup and 2028 Summer Olympics.[953]

Given the historic, national, and international significance of both the 2026 World Cup and the 2028 Summer Olympics for California and the United States, we authorize SCE to establish the HSECTMA. The costs recorded in the HSECTMA will be subject to a reasonableness review in SCE's next GRC. Therefore, SCE should file a Tier 1 advice letter with the Commission's Energy Division, within 30 days upon issuance of this decision, establishing the HSECTMA.

Finally, SCE also proposes to maintain the DER-DGRPMA and continue to track costs for future reasonableness review and recovery associated with SCE's DER-Driven Grid Reinforcement Program. TURN opposes SCE's request to maintain the DER-DGRPMA.[954] We authorize SCE to maintain the DER-DGRPMA but adopt TURN's recommendation that SCE shall demonstrate that the recorded costs are reasonable for rate recovery if it makes use of a DER-driven need analysis that is conducted as part of SCE's distribution planning process.[955]

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[953] Cal Advocates OB at 192-193.

[954] TURN OB at 131.

[955] TURN OB at 132.

12.2. Transmission Projects

12.2.1. Transmission Capital

The Transmission Projects component of SCE's GRC includes work SCE completes on its high voltage transmission system that is generally between 500 kV and 220 kV. While the majority of SCE's Transmission Projects-related work falls within FERC jurisdiction, some of these projects include components under Commission jurisdiction, including upgrades to the underlying subtransmission system and equipment supporting telecommunications, automation, and controls.[956]

For 2023-2025, SCE forecasts a total of $721.410 million in capital expenditures for Transmission Projects.[957] SCE forecasts its projects at the total company level, which includes both FERC-jurisdictional costs and Commission-jurisdictional costs, and requests that its forecasts be approved at the total company level.[958] SCE categorizes its Transmission Projects as either Grid Reliability Projects, Renewable Transmission Projects, or Transmission Economic Projects.[959] SCE also requests the Commission to approve its 2023-2025 forecast of $508.363 million for Grid Reliability projects, $166.629 million for Renewable Transmission Projects, and $11.777 million for Transmission Economic Projects.[960] Finally, SCE requests that the Commission authorize it to open the Renewable Transmission Projects Memorandum Account (RTPMA). SCE states that this memorandum account will allow it to track the

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[956] Ex. SCE-13, Vol. 7 at 107; *see also* Ex. SCE-02, Vol. 7 at 101.

[957] Ex. SCE-13, Vol. 7E2 at 108, Table III-19.

[958] Ex. SCE-13, Vol. 7 at 107.

[959] Ex. SCE-02, Vol. 7 at 105.

[960] Ex. SCE-13, Vol. 7 at 111.

Commission-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.

12.2.2. Parties' Positions

12.2.2.1. Cal Advocates

Cal Advocates recommends a decrease to all of SCE's Transmission Projects. Cal Advocates recommends that the Commission adopt a decrease of $22.5 million between 2023-2025 to all Transmission Projects which amounts to a modified capital expenditure total of $104.0 million between 2024-2025.[961] In support of this position, Cal Advocates makes the following recommendations: (1) the Commission should decrease SCE's capital expenditures for its Grid Reliability Projects to $84.5 million from $91.5 million;[962] (2) the Commission should decrease SCE's Renewable Transmission Projects request by $14.4 million;[963] and (3) SCE's dynamic line rating should be submitted as a separate application and removed from the GRC.[964] Specifically, with respect to decreasing SCE's Renewable Transmission Projects, Cal Advocates recommends removing the following projects: (1) Lugo-Victorville 500 kV Special Protection Scheme (SPS), Tours Solar Project, Syracuse Solar Project, and Calcite 220 kV Substation.[965]

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[961] Cal Advocates OB at 174.

[962] Cal Advocates OB at 175.

[963] Cal Advocates OB at 180.

[964] Ex. CA-07 at 32.

[965] Ex. CA-07 at 30-32.

12.2.2.2. Joint Truck OEMs

Joint Truck OEMs support SCE's request for transmission projects. Joint Truck OEMs state that load growth and the need to accommodate transportation electrification, especially the electrification of medium- and heavy-duty vehicles, will also require upgrades of certain sub-transmission and transmission facilities.[966]

12.2.2.3. SCE's Rebuttal

SCE opposes Cal Advocates' recommendations for an array of reasons. First, SCE states that Cal Advocates' recommendation to decrease SCE's Grid Reliability Projects to $84.517 million from $91.485 million is based on removing $2.083 million of Commission-jurisdictional capital expenditures associated with the Riverside Transmission Reliability Project and $4.885 million of Commission-jurisdictional capital expenditures associated with the IT Blanket.[967] SCE argues that it is unreasonable to remove a project from SCE's forecast because it experienced a delay.[968] SCE asserts that the operation date for the project changed due to delay outside of its control, particularly because of an outstanding Petition for Modification filed by the City of Norco requesting undergrounding of a portion of the project.[969]

Second, SCE argues that Cal Advocates' recommendation to reduce its Blanket IT costs is unreasonable because SCE does not yet know the exact project scope, nature of work, and type of resources that will be utilized to execute the work. In other words, SCE states that it was not able to estimate these costs with

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[966] Joint Truck OEMs OB at 27.

[967] Ex. CA-07 at 26.

[968] Ex. SCE-18, Vol. 1 at Section VI.E.

[969] Ex. SCE-13, Vol. 7 at 113.

project-to-project specificity in this GRC forecast for new and emergent projects because of the timing of this GRC.[970]

Next, SCE opposes Cal Advocates' recommendation to remove capital expenditures associated with four projects in its Renewable Transmission Projects forecast. SCE asserts that removal of these projects because of delays outside SCE's control is unreasonable.[971] SCE also states that Cal Advocates' position does not account for the fact that capital projects that are authorized but delayed do not go into permanent rate base unless and until they go into service.[972]

SCE also opposes Cal Advocates' recommendation to remove the Dynamic Line Ratings cost forecast. SCE states it is unreasonable to oppose the Dynamic Line Ratings cost forecast because: (1) it introduced evidence in support of the studies — conducted by the Department of Energy and the Rocky Mountain Institute — detailing the benefits of Dynamic Line Ratings;[973] (2) while SCE could not provide a formal quote for the Dynamic Line Ratings, it did provide detailed workpapers that account for additional software and hardware costs associated with installing new sensor equipment in areas where more granular weather data is required;[974] and (3) a lack of a fixed operation date is not a reason for rejecting the project.[975]

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[970] SCE OB at 148.

[971] SCE OB at 149.

[972] Ex. SCE-13, Vol. 7 at 117.

[973] Ex. SCE-13. Vol. 7 at 121.

[974] Ex. SCE-13, Vol. 7 at 121-122.

[975] SCE OB at 152.

12.2.3. Discussion

Grid Reliability Projects: As discussed above, Cal Advocates' capital expenditure forecast is based on the removal of two projects: Riverside Transmission Reliability Project and Transmission IT Blanket. First, Cal Advocates recommends that we remove the Riverside Transmission Reliability Project because the project has been delayed and the work on this project is currently suspended.[976] For SCE's part, SCE states that it will complete the project during this GRC cycle — especially since the Commission denied the Petition for Modification filed by the City of Norco.[977] SCE states this project is no longer on hold.[978] Given this, we adopt the Riverside Transmission Reliability Project. SCE has demonstrated both the reasonability of the project and the project's ability to move forward.

Next, we decline to reduce the costs associated with the Transmission IT Blanket. The Transmission IT Blanket is an estimate of what SCE has described as necessary costs it will incur for telecommunication infrastructure for new and emergent projects.[979] Cal Advocates' rationale for reducing SCE's budget is based upon a lack of historic costs and a vague budget from SCE. However, we find that SCE has demonstrated in the record that the costs are a reasonable estimate of forecasted Transmission IT Blanket costs.[980] We therefore adopt SCE's forecast for its Transmission IT Blanket to ensure there is sufficient funding for telecommunication infrastructure.

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[976] Cal Advocates OB at 177.

[977] Ex. SCE-13, Vol. 7 at 113.

[978] Ex. SCE-13, Vol. 7 at 113.

[979] Ex. SCE-13, Vol. 7 at 148.

[980] Ex. SCE-13, Vol. 7 at 113.

Renewable Transmission Projects: We decline to remove the following three projects from the Renewable Transmission Projects: (1) Lugo-Victorville 500 kV SPS; (2) Tours Solar Project; and (3) Syracuse Solar Project. Cal Advocates' recommendation for removal of these projects is based on an uncertain operation date.[981]

SCE has demonstrated that agency permitting and/or licensing review contributes to project delays. At the same time, SCE has primary responsibility for aspects of project management that may also affect permitting timelines and project in-service dates. For the two solar projects, we find the delays for the operation dates of these projects to be outside SCE's control due to delays from customer holds.[982] Therefore, we find it reasonable to authorize the forecasts for the above capital projects. We also adopt the Lugo-Victorville 500 kV SPS project into this 2025 TY GRC cycle because we find that the project is being completed and placed into service incrementally, despite a potential delay to the projected in-service date.

However, we decline to adopt the Calcite 220 kV Substation into this TY 2025 GRC cycle because the SCE project's permit request has yet to be submitted to the Commission. The Commission directs SCE to proactively collaborate with permitting and/or licensing agencies to help support an efficient review process and an improved forecast of in-service dates during the next GRC cycle.

Transmission Economic Projects: Cal Advocates recommends removing SCE's Commission-jurisdictional costs forecast of $4.642 million in 2026, $6.189 million in 2027, and $3.095 million in 2028 for Dynamic Line Ratings

[981] Ex. CA-07 at 32.

[982] Ex. SCE-18, Vol. 1 at 122; *see also* SCE-13, Vol. 7 at 117.

(DLR).[983] According to SCE, DLR may further increase transmission line rating accuracy and FERC has opened a proceeding to evaluate the economic and reliability benefits of DLR technology.[984] In support of its recommendation for removing the costs of DLR, Cal Advocates asserts that there is a: (1) lack of recent empirical studies and California-specific support for DLR deployment; (2) lack of documentation substantiating the proposed line items that compose the DLR budget; and (3) lack of a fixed operation date. Cal Advocates recommends that SCE should propose a DLR pilot program in a separate application to the Commission or through the Commission's EPIC program.[985] We agree. Indeed, it is reasonable and prudent for SCE to pursue a DLR strategy after FERC has fully evaluated the economic and reliability benefits of DLRs.[986] We adopt Cal Advocates' recommendation to remove DLRs from SCE's Transmission Economic Projects request, which results in a 2023-2028 Transmission Economic Projects capital expenditure total of $5.1 million and covers the attrition years (2026-2028).[987]

Renewable Transmission Projects Memorandum Account: Finally, SCE requests authorization for the establishment of the Renewable Transmission Projects Memorandum Account (RTPMA). SCE proposes to establish the RTPMA, effective January 1, 2025, to track the Commission-jurisdictional capital-related revenue requirement and capital-related expense associated with costs spent on renewable transmission projects that are incremental to the

[983] Ex. CA-07 at 32.

[984] Ex. SCE-02, Vol. 7 at 117.

[985] Ex. CA-07 at 33.

[986] Ex. SCE-02, Vol. 7 at 117.

[987] Cal Advocates OB at 182.

amounts authorized in the 2025 GRC.[988] SCE's request is uncontested. We find SCE's request reasonable and adopt the RTPMA.

Therefore, SCE should file a Tier 1 advice letter with the Commission's Energy Division, within 30 days upon issuance of this decision, establishing the RTPMA.

12.3. Engineering O&M

12.3.1. Discussion

The Engineering Business Planning Element (BPE) includes SCE's Grid Engineering costs that are required to ensure the grid is reliable, capable of providing adequate power, and allows for interconnection of new generation sources to accommodate load growth and meet California's Renewables Portfolio Standard requirements.[989] The Engineering BPE also includes Load Side Support costs, which support the investigative and engineering work to address customer-reported concerns with power quality.[990] For the 2025 TY, SCE forecasts $13.845 million for Engineering O&M expenses ($12.370 million for Grid Engineering and $1.475 million for Load Side Support).[991]

No intervenor contested this forecast. We find SCE's request reasonable and adopt its uncontested Engineering O&M forecast.

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[988] SCE OB at 150.

[989] Ex. SCE-02, Vol. 7, Chapter IV.

[990] Ex. SCE-02, Vol. 7 at 119.

[991] Ex. SCE-13, Vol. 7 at 2; Ex. SCE-02, Vol. 7 at 124, 128.

13. New Service Connections and Customer Requested System Modifications

13.1. Uncontested Programs

13.1.1. New Service Connections: Streetlights New Service Connections

For 2023-2025, SCE forecasts $46.832 million in capital expenditures for Streetlights New Service Connections based on the five-year average of recorded expenditures.[992] This forecast includes recorded expenditures of $14.354 million.[993] This forecast is unopposed.

13.1.2. New Service Connections: Commercial Electric Vehicle Service Extensions Pursuant to Rule 29

For 2023-2025, SCE forecasts $14.476 million in capital expenditures for this activity.[994] This work category includes the installation or upgrade of electrical service facilities to support utility-side commercial electric vehicle charging infrastructure pursuant to SCE's Tariff Rule 29. SCE testifies that this forecast was derived by determining a forecast number of Rule 29 project sites anticipated to be completed each year and multiplying that by SCE's forecast cost per project site.[995] This forecast is unopposed, with Walmart stating that SCE's forecast may be too low.[996]

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[992] Ex. SCE-13, Vol. 8 at 13-14, Table II-6.

[993] Ex. SCE-13, Vol. 8 at 14, Table II-6.

[994] Ex. SCE-13, Vol. 8 at 15, Table II-7.

[995] Ex. SCE-13, Vol. 8 at 14.

[996] Ex. Walmart-01 at 10-12.

13.1.3. Customer Requested System Modifications

While Cal Advocates and TURN recommend reductions to SCE's Rule 20 forecasts, which are addressed further below, no party served testimony opposing SCE's Relocations, Added Facilities, and Wholesale Distribution Access Tariff (WDAT)/Transmission Owner Tariff (TOT)/Gen-Tie forecasts and testimony. Thus, SCE requests that the following 2023-2025 SCE forecasts be adopted as reasonable: (1) Distribution Relocations, $179.576 million; (2) Transmission Relocations, $57.204 million; (3) Distribution Added Facilities, $32.403 million; (4) Transmission/Substation Added Facilities (SCE Financed) — $39.077 million; (5) Transmission/Substation Added Facilities (Customer Financed), $93.320 million; (6) WDAT/TOT/Gen-Tie (SCE Funded), $12.172 million; and (7) WDAT/TOT/Gen-Tie (Customer Funded) — $292.046 million.[997]

13.2. Contested Programs

New Service Connections are necessary for new customers to receive electrical service from SCE. New Service Connections encompasses the following activities: (1) Residential New Service Connections; (2) Commercial New Service Connections; (3) Agricultural New Service Connections; (4) Streetlights New Service Connections; and (5) Commercial Electric Vehicle Service Extensions Pursuant to Rule 29. SCE uses the gross meter sets from the retail sales forecast as the basis for developing its capital expenditures forecasts for the residential, commercial, and agricultural new service connections. In

[997] SCE OB at 158-159.

total, SCE forecasts $1.768 billion in capital expenditures from 2023-2025 for New Service Connections and Customer Requested System Modifications activities.[998]

13.2.1. New Service Connections: Residential New Service Connections

For 2023-2025, SCE forecasts $445.727 million in capital expenditures for Residential New Service Connections.[999]

In developing its forecast for Residential New Service Connections, SCE states it followed the Commission's findings in the 2021 GRC Track 1 Decision and set its meter forecast on a blend of Moody's forecast of housing starts and the more-conservative IHS Markit forecast of housing starts.[1000] SCE testifies that in deriving its forecast, SCE multiplied the forecast volume of residential meter sets by the simple five-year average of the recorded cost per unit associated with residential meter sets that were installed during 2018-2022.[1001]

In support of its forecast, SCE makes an array of arguments.[1002] SCE states that this forecast incorporates three adjustments made in rebuttal testimony. First, SCE proposes the Commission authorize SCE's 2023 recorded expenditures in place of SCE's original 2023 forecast.[1003] Second, SCE states it updated its 2024 forecast to reflect budget-based authorized capital amounts from the 2021 GRC Track 4 Decision (D.23-11-096).[1004] Third, SCE states it reduced its 2025 forecast

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[998] Ex. SCE-13, Vol. 8 at 2, Table I-1.

[999] Ex. SCE-13, Vol. 8 at 5, Table II-3.

[1000] Ex. SCE-02, Vol. 8 at 5 and 13 and Ex. SCE-13, Vol. 8 at 4.

[1001] Ex. SCE-02, Vol. 8 at. 13-14 and Ex. SCE-13, Vol. 8 at 4.

[1002] Ex. SCE-13, Vol. 8 at 5, Table II-3.

[1003] Ex. SCE-13, Vol. 8 at 5.

[1004] Ex. SCE-13, Vol. 8 at 5.

by $0.306 million due to Operational Excellence savings related to reducing the number of required resources through increasing efficiencies in this activity.[1005] Cal Advocates and TURN contest this forecast.

13.2.2. New Service Connections: Commercial New Service Connections

For 2023-2025, SCE forecasts $355.954 million in capital expenditures for Commercial New Service Connections.[1006] SCE testifies that this forecast is comprised of two components. One component consists of the Rule 15 commercial line extension work driven by commercial EV service extension work performed pursuant to Rule 29.[1007] The other component includes all other Rule 15 commercial line extension work and all Rule 16 commercial service extension work.[1008]

To derive its forecast, SCE states it used the forecast number of Rule 29 service extension project sites expected to have associated Rule 15 line extension work. SCE states it then multiplied this by the average cost per site for Rule 15 commercial line extension work associated with commercial electric vehicle service extension projects.[1009] For the second component, SCE: (1) adopted a five-year adjusted average of the recorded cost per unit associated with commercial meter sets that were installed during 2018-2022; and (2) then

[1005] Ex. SCE-13, Vol. 8 at 4.

[1006] Ex. SCE-13, Vol. 8 at 10, Figure II-4.

[1007] Ex. SCE-13, Vol. 8 at 9.

[1008] Ex. SCE-13, Vol. 8 at 9-10.

[1009] Ex. SCE-13, Vol. 8 at 10.

multiplied this average by its meter set forecast.[1010] TURN opposes SCE's forecast.

13.2.3. New Service Connections: Agricultural New Service Connections

For 2023-2025, SCE forecasts $16.352 million in capital expenditures for Agricultural New Service Connections.[1011] To derive its forecast, SCE used the recorded five-year average of the agricultural meter sets installed from 2018-2022 to calculate an annual gross meter set forecast and then multiplied that meter set forecast by the five-year average of the recorded cost per unit.[1012] SCE proposes the Commission authorize SCE's 2023 recorded expenditures of $5.798 million in place of SCE's original 2023 forecast of $4.941 million.[1013] TURN opposes SCE's forecast.

13.2.4. Customer Requested Modifications: Rule 20A Conversions

For 2023-2025, SCE forecasts $63.262 million for Rule 20A conversions.[1014] SCE converts existing distribution, transmission, and telecommunication overhead facilities to underground facilities pursuant to SCE's Tariff Rule 20.[1015] Governmental agencies, developers, and individual customers (residential and businesses) request conversion projects based on the criteria established in Tariff Rule 20 (A, B, or C). Rule 20A is applicable to undergrounding projects for which the governing body of the city or county in which such electric facilities

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[1010] Ex. SCE-13, Vol. 8 at 9-10.

[1011] Ex. SCE-13, Vol. 8 at 12, Table II-5.

[1012] Ex. SCE-13, Vol. 8 at 11-12.

[1013] Ex. SCE-13, Vol. 8 at 12, Table II-5.

[1014] Ex. SCE-13, Vol. 8 at 19.

[1015] Ex. SCE-13, Vol. 8 at 17.

are, and will be, located has determined that such undergrounding is in the general public interest for one or more of five specified reasons. In addition, a minimum of 600 feet or one city block must be converted to underground facilities. These projects are customer-funded.[1016]

SCE states that given the trend of increasing costs from 2018 to 2022, SCE used the 2022 last recorded year expenditures of $18.84 million and then escalated this amount to forecast the annual expenditures. SCE also states that because SCE has a Rule 20 Balancing Account, it conducted an analysis to forecast whether there would be an overcollection or undercollection in the Rule 20A subaccount at year end 2024.[1017] SCE testifies that based on SCE's updated analysis in rebuttal testimony, SCE forecasts that the 2024 year-end balance in the Rule 20A subaccount will be an overcollection of $3.732 million.[1018] Therefore, SCE states it reduced its unadjusted 2025-2028 Rule 20A forecasts by $0.933 million per year in constant 2022$ ($3.732 million divided by four).[1019] SCE also recommends that the Commission allow SCE to provide the actually recorded balance in the Rule 20A subaccount as of December 31, 2024 in the advice letter implementing the final decision in this proceeding and to use this actually recorded balance to reduce SCE's 2025-2028 forecasts if that recorded balance is an overcollection.[1020]

[1016] Ex. SCE-13, Vol. 8 at 18.

[1017] Ex. SCE-13, Vol. 8 at 18.

[1018] Ex. SCE-13, Vol. 8 at 25, Table III-10.

[1019] Ex. SCE-13, Vol. 8 at. 25-26, Table III-11.

[1020] Ex. SCE-13, Vol. 8 at 26.

Cal Advocates opposes SCE's Rule 20A forecasts, which we discuss below. TURN sponsored testimony addressing Rule 20A Conversions.[1021] Following SCE's rebuttal testimony, TURN states it conferred with SCE, and TURN agrees that SCE's revised forecast for Rule 20A Conversions in its rebuttal testimony is reasonable.[1022]

13.2.5. Customer Requested Modifications: Rule 20B and Rule 20C Conversions

Rule 20B capital expenditures include the costs to convert distribution, telecommunication, and transmission overhead facilities to underground facilities under SCE Tariff Rule 20B at the request of governmental agencies, developers, and customers.[1023] These projects generally arise when there are overhead lines on both sides of the street, for a minimum of 600 feet or one city block, and a governmental agency or private party wishes to eliminate the visual impact of those overhead lines or must remove the lines as a condition to obtain permitting from another governmental agency. With Rule 20B conversions, customers pay for the removal of SCE's existing overhead system and for a credit equal to building a new equivalent overhead line, while SCE pays for the remainder of the cost of undergrounding.[1024]

Rule 20C projects generally arise when an individual property owner or small developer of a new project wishes to remove existing overhead lines less than 600 feet in total length, or on one side of the street, or overhead lines on private property. With Rule 20C conversions, the applicant pays for the full cost

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[1021] Ex. TURN-10.

[1022] TURN OB at 154.

[1023] Ex. SCE-13, Vol. 8 at 26.

[1024] Ex. SCE-13, Vol. 8 at 26.

of undergrounding, minus a credit for the estimated salvage value of the removed electrical facilities.[1025]

Cal Advocates recommends a reduction to SCE's 2023 Transmission Rule 20B forecast based on preliminary year-to-date 2023 recorded costs that were lower than SCE's original 2023 forecast, which we discuss further, below.

13.3. Parties' Positions

13.3.1. Cal Advocates

13.3.1.1. New Service Connections: Residential New Service Connections

In response to SCE's Residential New Service Connections, Cal Advocates recommends a 2023-2025 forecast of $375.574 million, which includes the following: (1) $129.021 million in 2023; (2) $121.770 million in 2024; and (5) $124.783 million in 2025. Cal Advocates' recommendation is $2.261 million less than SCE's forecast of $131.282 million in 2023, $8.998 million less than SCE's forecast of $130.768 million in 2024, and $17.386 million less than SCE's forecast of $142.169 million in TY 2025.[1026]

In its testimony, Cal Advocates details its methodology. Cal Advocates states that it derived its total residential capital expenditures forecast by applying the last recorded year capital cost per meter set of $3,870 to the forecast volume of residential gross meter sets plus the Employee Compensation program adjustment forecasts, which gives estimated forecasts of $129.021 million in 2023, $121.770 million in 2024, and $124.783 million in TY 2025.[1027] In support of its recommendation, Cal Advocates argues SCE has not justified its request nor has

[1025] Ex. SCE-13, Vol. 8 at 26.

[1026] Cal Advocates OB at 202-203.

[1027] Ex. CA-04 at 32-33.

it explained sufficiently how SCE's forecast methodology is appropriate for the 2023-2025 Residential New Service Connections capital expenditures.[1028]

13.3.1.2. Customer Requested System Modifications: Rule 20A Conversions

Cal Advocates' recommendation for SCE's Rule 20A conversion capital expenditures is $12.810 million in 2023, $12.810 million in 2024, and $12.810 million in TY 2025.[1029] Cal Advocates' recommendation is $7.150 million less than SCE's request of $19.960 million in 2023, $8.044 million less than SCE's forecast of $20.854 million in 2024, and $7.498 million less than SCE's forecast of $20.308 million in TY 2025. Cal Advocates states that it developed its recommendation by utilizing SCE's five-year average Rule 20A conversion project costs from 2018 to 2022.[1030] Cal Advocates argues that SCE has not justified its Rule 20A conversion capital expenditures and SCE's forecasts should thus be reduced.[1031]

13.3.1.3. Customer Requested System Modifications: Rule 20B and Rule 20C Conversions

While Cal Advocates does not oppose SCE's Distribution Rule 20B and Rule 20C forecasts and methodology or SCE's Transmission Rule 20C forecast and methodology, Cal Advocates does recommend reductions.[1032]

Cal Advocates' recommendation for SCE's Rule 20B and Rule 20C conversion capital expenditures is $34.754 million in 2023, $36.106 million in

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[1028] Cal Advocates OB at 204-209.

[1029] Ex. CA-04 at 22-24.

[1030] Cal Advocates OB at 199.

[1031] Cal Advocates OB at 199-202.

[1032] Ex. CA-04 at 28; *see also* Cal Advocates OB at 210.

2024, and $37.353 million in TY 2025.[1033] Cal Advocates' recommendation is $2.697 million less than SCE's request of $37.451 million in 2023, $0 million less than SCE's forecast of $36.106 million in 2024, and $0 million less than SCE's forecast of $37.353 million in TY 2025.[1034]

In support of its reductions, Cal Advocates states it based its recommendations on preliminary year-to-date 2023 recorded costs.[1035] Cal Advocates states it utilized those preliminary year-to-date 2023 recorded costs and applied a 20 percent increase to calculate its recommended 2023 capital expenditure amount of $0.638 million for Transmission Rule 20B.[1036]

13.3.2. TURN

13.3.2.1. Residential New Service Connections

In response to SCE's Residential New Service Connections, TURN recommends a 2023-2025 forecast of $380.202 million which breaks down as follows: (1) $118.940 million in 2023; (2) $122.979 million in 2024;[1037] and (3) $138.283 million in 2025.[1038]

TURN argues that SCE's residential gross meter set forecast is flawed. TURN asserts that SCE relies on an overly optimistic housing forecast and underperforming historical regression models.[1039] Thus, TURN recommends a forecast of residential new meters based on the most recent 10-year average

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[1033] Ex. CA-04 at 30-31.

[1034] Cal Advocates OB at 210.

[1035] Ex. CA-04 at 30-31.

[1036] Ex. CA-04 at 31.

[1037] Ex. TURN-08E at 3.

[1038] TURN OB at 138.

[1039] TURN OB at 138-141.

growth rate in meters, not based on housing forecasts.[1040] TURN states it bases its forecast on historical data instead of proprietary third party data for transparency purposes.[1041] TURN explains that it calculates the meter growth rate by comparing the number of new meters added in one year to the total number of residential meters at the end of the prior year.[1042]

13.3.2.2. Commercial New Service Connections

In response to SCE's forecast, TURN recommends Commercial New Service Connections capital expenditures of $94.166 million in 2023, $93.766 million in 2024,[1043] and $93.150 million in Test Year 2025.[1044] To calculate this forecast, TURN used its own forecast of commercial meter sets. TURN contends that SCE's forecast of commercial meter sets is not aligned with reality.[1045] TURN argues that since the pandemic, the economy has demonstrated a general contraction of the commercial office space market, as workers continue to spend more time remote.[1046] TURN testifies that occupancy and sales for commercial real estate continue to be weak, and other sources discuss rising contractor costs, land prices, and uncertainty as rationales for the

[1040] Ex. TURN-08 at 11.

[1041] Ex. TURN-08 at 2.

[1042] TURN OB at 141.

[1043] Ex. TURN-08E at 3, Figure 5.

[1044] TURN OB at 138.

[1045] Ex. TURN-08 at 14-15.

[1046] Ex. TURN-08 at 14.

downward trend.[1047] TURN states that its forecast simply follows the current trend without incorporating additional assumptions.[1048]

13.3.2.3. Agricultural New Service Connections

In response to SCE's forecast, TURN recommends 2023-2025 capital expenditures of $9.424 million. TURN's recommendation consists of the following: (1) $3.154 million in 2023; (2) $3.280 million in 2024;[1049] and (3) $3.010 million in 2025.[1050] TURN testifies that there is a steadily declining trend in the number of new agricultural meters from 2018-2022 and continuing through 2023.[1051] TURN argues that SCE's forecast of a near-term rebound in the number of agricultural new connections is unsupported.[1052]

13.3.3. SCE's Rebuttal

13.3.3.1. New Service Connections: Residential New Service Connections

SCE argues that the Commission should reject Cal Advocates' and TURN's recommendations for the Residential New Service forecast. In support of its contention, SCE makes three primary arguments. First, SCE states its actual 2023 recorded expenditures of $154.433 million support the reasonableness of SCE's forecast and unreasonableness of the intervenors' forecasts.[1053] SCE testifies that this recorded amount is higher than SCE's original 2023 forecast of $131.282 million, which undermines Cal Advocates' and TURN's arguments that

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[1047] Ex. TURN-08 at 15.

[1048] Ex. TURN-08 at 16.

[1049] Ex. TURN-08E at 3, Figure 4; *see also* Ex. TURN-08E at 21, Figure 21.

[1050] TURN OB at 138.

[1051] Ex. TURN-08 at 17.

[1052] TURN OB at 151-152.

[1053] Ex. SCE-13, Vol. 8, at 5, Table II-3.

SCE's forecasting methodology is overly optimistic and bound to result in inflated forecasts.[1054] SCE also asserts that Cal Advocates' and TURN's proposals create significant risk that SCE will be underfunded for this necessary activity.[1055]

Second, SCE argues that Cal Advocates' and TURN's forecasts of residential meter sets are fundamentally flawed. SCE states that Cal Advocates relies on its own, flawed housing starts forecast and TURN miscalculates the historical average growth rate in gross meter sets.[1056] Finally, SCE argues that Cal Advocates and TURN make escalation proposals that are methodologically flawed and inconsistent with accepted GRC forecasting practice.[1057] SCE states that Cal Advocates' use of a non-escalated historical cost per meter set should be rejected as inaccurate and inconsistent with accepted GRC forecasting practice.[1058] With respect to TURN, SCE states that its practice of escalating recorded dollars to constant dollars to develop a normalized five-year average does not "internalize" or otherwise double count prior rates of inflation.[1059]

13.3.3.2. New Service Connections: Commercial New Service Connections

SCE asserts that TURN's forecast for new commercial meter sets and its corresponding recommended reduction should be rejected. SCE argues that TURN's proposed commercial meter set forecasts are significantly below recent

[1054] Ex. SCE-02, Vol. 8 at 10.

[1055] SCE OB at 155.

[1056] Ex. SCE-18, Vol. 1 at 75-88.

[1057] Ex. SCE-13, Vol. 8 at 8-9.

[1058] SCE OB at 155-156.

[1059] SCE OB at 156.

history and the long-term average.[1060] SCE contends that despite the number of non-residential meter set installations experiencing a significant bounce in 2022 and 2023 from the lows recorded during the COVID-19 period, the forecast by TURN suggests a continuous decrease in installations throughout this GRC period starting from levels even lower than the 2021 recorded installs and eventually dropping down to as few as 2,031 installations by 2028.[1061] SCE states that this position is unreasonable.

For its part, SCE states that its proposal of flat growth for commercial meter installations during this GRC period is reasonable.[1062] SCE asserts that flat growth is reasonable given the increases seen in 2022 and 2023 and for the fact that upcoming global sports events, including the 2026 World Cup and the 2028 Olympics, will take place in SCE's service area.[1063]

13.3.3.3. New Service Connections: Agricultural Connections

SCE argues that the Commission should reject TURN's forecast of new agricultural meter sets and its corresponding recommended reductions. SCE asserts that TURN's proposed agricultural meter set forecast is lower in each year than the actual number recorded of 118 in 2023, which was the lowest annual installation total since 1998.[1064]

[1060] SCE OB at 157.

[1061] Ex. SCE-18, Vol. 1 at 84-85.

[1062] Ex. SCE-18, Vol. 1 at 85, Figure III-3.

[1063] Ex. SCE-18, Vol. 1 at 85.

[1064] Ex. SCE-18, Vol. 1 at 84.

13.3.3.4. Customer Requested System Modifications Connections: Rule 20A Conversions

SCE argues that Cal Advocates' Rule 20A recommendation is unreasonable and should be rejected for a few reasons. First, SCE asserts that Rule 20A costs trended upwards from 2018 to 2022, and using the last recorded year for forecasting purposes, like SCE did, is appropriate when historical costs have trended in a certain direction over three or more years.[1065] SCE states that this upward trend continued through 2023, further demonstrating the reasonableness of its forecast.[1066]

Second, SCE states the Commission's decision in D.21-06-013 to discontinue approval of new work credits for allocation by the electric utilities after December 31, 2022 resulted in a high volume of customer participation in Rule 20A projects because of customer concerns that existing credits might be lost in the future if not used.[1067] SCE states that it expects the high volume of customer participation seen in 2022 to be sustained through this GRC period.[1068]

Finally, SCE asserts that its actual recorded costs in 2023 for the entire Rule 20A program were higher than SCE's forecast and higher than the 2022 recorded amount.[1069] SCE states that this demonstrates that its forecasting methodology is reasonable and should be approved.[1070]

[1065] SCE OB at 161 citing to D.21-08-036 at 72-73.

[1066] Ex. SCE-13, Vol. 8 at 19, Table III-9.

[1067] SCE OB at 161.

[1068] Ex. SCE-13, Vol. 8 at 24.

[1069] Ex. SCE-13, Vol. 8 at 23-24.

[1070] SCE OB at 162.

13.3.3.5. Customer Requested System Modifications Connections: Rule 20B

In response to Cal Advocates' proposed reduction to SCE's 2023 Transmission Rule 20B forecast, SCE asserts Cal Advocates' proposal is moot. SCE states that it recommends that the Commission authorize SCE's 2023 recorded expenditures in place of SCE's original forecast.[1071]

13.4. Discussion

13.4.1. Contested Programs

13.4.1.1. New Service Connections: Residential New Service Connections

We authorize and adopt capital expenditure forecasts of $154.433 million in 2023 (recorded), $149.431 million in 2024, and $138.283 million in 2025 for Residential New Service Connections.

For 2023 and 2024, we adopt SCE's proposal, which reflects 2023 recorded expenditures and the 2024 capital forecast agreed-upon and adopted in D.23-11-096.[1072] We agree with SCE that these are the appropriate capital expenditures to adopt in these respective years.

For 2025, we adopt TURN's proposal. First, we are persuaded that SCE's forecast model based on housing starts results in overly optimistic meter and customer forecasts. TURN bases its forecast on its calculation of the most recent 10-year average growth rate in meters, which we find reasonable. We also note that TURN has addressed SCE's rebuttal arguments on escalation by updating its forecast to use standard escalation consistent with SCE's unit cost methodology.[1073] Second, we are not persuaded by Cal Advocates' housing

[1071] Ex. SCE-13, Vol. 8 at 29.

[1072] Ex. SCE-18, Vol. 1 at 118-119.

[1073] SCE OB at 136.

starts forecast and agree with SCE that Cal Advocates' use of a non-escalated historical cost per meter is unsupported.

13.4.1.2. New Service Connections: Commercial New Service Connections

We authorize and adopt capital expenditure forecasts of $130.061 million in 2023 (recorded), $91.196 million in 2024, and $93.150 million in 2025 for Commercial New Service Connections.

For 2023 and 2024, we adopt SCE's proposal, which reflects 2023 recorded expenditures and the 2024 capital forecast adopted in D.23-11-096. As in the Residential New Service Connections request, we agree with SCE that these are the appropriate forecasts to adopt.

For 2025, we adopt TURN's proposal, which reflects a more conservative meter forecast for 2025. We are persuaded by the evidence provided by TURN showing declining trends in the number of new commercial meters from 2016-2022 and commercial real estate market conditions.[1074] We are not persuaded by SCE's arguments regarding growth rates throughout the GRC period.[1075] Unlike the 2021 GRC,[1076] this decision does not adopt a budget-based forecast for Commercial New Service Connections capital additions in the 2026-2028 post-test years, and therefore arguments concerning post-test year growth rates and 2028 forecasts are moot. We find TURN's methodology and 2025 forecast to be reasonable.

[1074] Ex. TURN-08E at 18-19.

[1075] Ex. SCE-18, Vol. 1 at 84-85.

[1076] D.21-08-036 at 549.

13.4.1.3. New Service Connections: Agricultural New Service Connections

We authorize and adopt TURN's 2024 and 2025 forecasts for the agricultural customer class and its capital forecasts for SCE's Agricultural New Service Connections. We also authorize and adopt SCE's 2023 recorded expenditures for Agricultural New Service Connections. This results in authorized capital expenditures of $5.798 million in 2023, $3.280 million in 2024, and $3.010 million in TY 2025.[1077] We are unpersuaded by SCE's arguments in support of higher agricultural customer class forecasts and capital expenditures.

We are persuaded by the evidence presented by TURN that the number of new agricultural meters in SCE's service territory is not increasing as rapidly as SCE argues.[1078] Several factors presented by TURN lead us to conclude TURN's agricultural forecast is reasonable and should be adopted. These factors include the following: (1) decreased availability of land and agricultural land in SCE's service territory; (2) challenges with droughts; and (3) urban population growth.[1079] And while total agricultural meters have recently increased, the rate of growth continues to decline. TURN has shown that new agricultural meter installations have dropped from over 500 per year to just over 100 per year.[1080]

In short, we authorize and adopt TURN's 2024-2025 forecasts for the agricultural customer class and its capital forecasts which results in authorized capital expenditures of: (a) $5.798 million in 2023; (b) $3.280 million in 2024; and (c) $3.010 million in TY 2025.

[1077] Ex. TURN-08E at 21, Figure 21.

[1078] SCE OB at 235; *see also* TURN OB at 151-152.

[1079] Ex. TURN-08E at 16-17.

[1080] Ex. TURN-08E at 17.

13.4.1.4. Customer Requested System Modifications: Rule 20A Conversions

We authorize and adopt SCE's forecast of $63.262 million for Rule 20A conversions.[1081]

SCE's forecasting methodology is reasonable. While Cal Advocates uses a five-year average of recorded costs as the basis of its recommendation, we are persuaded by SCE that using the last recorded year accurately reflects the level of spending expected to be seen between 2023-2028. For example, SCE has shown that Rule 20A costs have trended upwards from 2018 to 2022.[1082] Indeed, these costs are associated with projects that include undergrounding of SCE's distribution, transmission, and telecommunication facilities.[1083] The record before us does not show that costs for these types of undergrounding activities will mirror a five-year historical average. In fact, there is an upward trend and an increased interest in these types of activities.[1084] Thus, SCE's forecast use of the last recorded year is appropriate for use and authorization.

Within 30 days upon issuance of this decision, SCE shall file a Tier 2 advice letter with the Commission's Energy Division that discusses the actually recorded balance in the Rule 20A subaccount as of December 31, 2024. SCE shall use this actually recorded balance to reduce SCE's 2025-2028 forecasts if that recorded balance is an overcollection.

[1081] Ex. SCE-13, Vol. 8 at 17, Table III-8.

[1082] Ex. SCE-13, Vol. 8 at 22.

[1083] Ex. SCE-02, Vol. 8 at 47.

[1084] Ex. SCE-13, Vol. 8 at 23.

In conclusion, we find that SCE's forecasting methodology for Rule 20A conversion projects is reasonable. Therefore, we authorize and adopt SCE's forecast of $63.262 million for Rule 20A conversions.

13.4.1.5. Customer Requested System Modifications: Rule 20B and Rule 20C Conversions

We authorize and adopt SCE's 2023-2025 forecast of $119.600 million in capital expenditures for Rule 20B and Rule 20C conversions. This amounts to $64.534 million for Rule 20B conversions[1085] and $55.066 million for Rule 20C conversions.[1086]

We decline to adopt Cal Advocates' recommended reduction to SCE's 2023 Transmission Rule 20B forecast. Cal Advocates based its recommendation on a preliminary year-to-date 2023 recorded cost.[1087] However, SCE is requesting authorization of its 2023 recorded expenditures.[1088] Thus, this issue is moot.

13.4.2. Uncontested Programs

The following 2023-2025 SCE forecasts are uncontested. SCE has justified the reasonableness of these uncontested forecasts and, therefore, we find reasonable and approve these activities and forecast capital costs:

- Commercial Electric Vehicle Service Extensions Pursuant to Rule 29 — $14.476;[1089]
- Distribution Added Facilities — $32.403 million;

[1085] Ex. SCE-13, Vol. 8 at 31, Table III-14.

[1086] Ex. SCE-13, Vol. 8 at 32, Table III-16.

[1087] Ex. CA-04 at 30-31; *see also* Cal Advocates OB at 213.

[1088] Ex. SCE-13, Vol. 8, at 29; *see also* SCE OB at 163.

[1089] Ex. SCE-13, Vol. 8 at 15, Table II-7.

- Distribution Relocations — $179.576 million; [1090]
- Streetlights New Service Connections — $46.832 million;[1091]
- Transmission Relocations — $57.204 million;
- Transmission/Substation Added Facilities (Customer Financed) — $93.320 million;
- Transmission/Substation Added Facilities (SCE Financed) — $39.077 million;
- WDAT/TOT/Gen-Tie (Customer Funded) — $292.046 million; and
- WDAT/TOT/Gen-Tie (SCE Funded) — $12.172 million.[1092]

14. Poles

14.1. Poles

SCE's O&M request is $1.289 million. No party challenges this request for O&M expense for the 2025 TY. No party challenges SCE's 2023 and 2025 Capital Expenditure Forecast. However, Cal Advocates challenges one program component of the Capital Expenditure request: the 2024 Transmission Deteriorated Pole Replacement Program. Otherwise, the 2023, the remaining 2024, and the 2025 Capital Expenditure requests are unopposed.

14.1.1. Pole Load and Deteriorated Pole Balancing Account

In D.15-11-021, the Commission approved the Pole Loading Program (PLP). D.15-11-021 also approved a two-way balancing account. The Pole Loading and Deteriorated Pole Programs Balancing Account (PLDPBA) allows SCE to recover PLP O&M and Capital costs, as well as Deteriorated Pole

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[1090] Ex. SCE-13, Vol. 8 at 17, Table III-8.

[1091] Ex. SCE-13, Vol. 8 at 14, Table II-6.

[1092] Ex. SCE-13, Vol. 8 at 17, Table III-8.

Program Capital costs. The PLDPBA was authorized to reduce risk to customers from unknown costs associated with PLP such as estimates in support of operational plans, cost forecasts, and failure rates.[1093]

Upon approval of the PLDPBA, the Commission allowed a 15 percent cap on all expenditures for the balancing account. Additionally, all recorded balancing account costs are CPUC-jurisdictional, which means only CPUC-associated costs are recorded. The PLDPBA is reviewed on a yearly basis by the Commission in SCE's Energy Resource and Recovery Account (ERRA) Review filing.[1094] Any over- or under-collection of the PLDPBA is transferred to the Base Revenue Requirement Balancing Account (BRRBA) to be returned to or recovered from customers. The 2021 SCE GRC Decision authorized the continuation of the PLDPBA.[1095]

Forecast: In this GRC, SCE proposes discontinuing the PLDPBA because the PLP is ending. SCE states that the established Deteriorated Pole Program will continue with routine inspection cycles for poles.[1096] With the end of the PLP, SCE states that the PLDPBA is no longer necessary beginning in 2025.[1097] This request is uncontested.

14.1.2. Pole Loading Program Closeout

SCE performed a one-time assessment of all poles through its PLP. SCE states that this activity improved the safety and reliability of the electric grid by identifying and replacing overloaded poles. SCE also states that the improved

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[1093] Ex. SCE-02, Vol. 9 at 7.

[1094] Ex. SCE-02, Vol. 9 at 7.

[1095] Ex. SCE-02, Vol. 9 at 7.

[1096] Ex. SCE-02, Vol. 9 at 7.

[1097] Ex. SCE-02, Vol. 9 at 7.

level of safety and reliability will be maintained by SCE's ongoing Pole-related programs. Through the PLP, SCE assessed poles to identify and repair or replace poles that did not meet GO 95 loading, temperature, and safety factor requirements.[1098] As a result of a 2013 wind study, SCE implemented increased wind loading criteria in many areas and in some locations added a new 24 pounds per square foot wind loading specification. PLP assessments began in January 2014 with the initial focus on the highest-risk areas including high fire areas. The revised wind loadings were implemented in March 2014.[1099]

SCE testifies that PLP assessments were performed to determine a pole's safety factor. PLP assessments required a field assessment and a desktop analysis to calculate each pole's safety factor. Inputs to the analysis of the pole included the physical attributes, its attachments, and the applicable wind loading. According to SCE, the field assessment measured, or validated, the pole's attributes (type of pole, species for wood poles, height, and class) and the type and size of equipment it supported. Collecting the data to perform a pole loading calculation required a field assessor who had to be able to access poles throughout SCE's service area, including those in remote terrain and other difficult to access locations, such as customer backyards, in order to take accurate measurements.[1100] Assessors had to measure the ground line circumference and have sufficient room around the pole to measure attachment heights and span

[1098] Ex. SCE-02, Vol. 9 at 8.

[1099] Ex. SCE-02, Vol. 9 at 8.

[1100] Ex. SCE-02, Vol. 9 at 9.

lengths. The information collected during the field assessment was input to perform a desktop analysis to calculate the pole's safety factor.[1101]

Next, SCE states that PLP Repairs were conducted. SCE states that PLP Repairs involved both the design and installation or modification of guy wires. The design work involves determining the appropriate size and placement of a guy wire(s) that conforms to SCE design standards and produces a compliant safety factor. Once the design work is completed, the repair notification is sent to a construction crew. The drawing created during the design process was used by the construction crew in performing the repair work in the field. The guy wire repair was completed by either an SCE or contractor crew.[1102]

Forecast: SCE states that the PLP recorded costs for repairs will end in 2023, and thus there will be no forecast costs for the 2025 TY.[1103] These costs are uncontested.

14.1.3. Intrusive Pole Inspections

SCE states that it intrusively inspects poles through the Intrusive Pole Inspection (IPI) Program. The IPI Program is required for SCE's approximately 1.3 million wood poles located in varying climate areas, such as coastal and desert climates throughout SCE's 50,000 square-mile service area. Environmental factors such as decay, fungi, and insect attacks may cause degradation of the inner portion of a wood pole, which may not be detected by visual inspections.[1104] SCE states that it established the IPI Program to comply

[1101] Ex. SCE-02, Vol. 9 at 9.

[1102] Ex. SCE-02, Vol. 9 at 12.

[1103] Ex. SCE-02, Vol. 9 at 11.

[1104] Ex. SCE-02, Vol. 9 at 14.

with GO 165, which became effective in 1997.[1105] An intrusive inspection involves drilling into the pole's interior to identify and measure the extent of internal decay that is typically undetectable with external observation alone.[1106]

SCE's inspection standards describe six types of inspections satisfying this definition which apply different combinations of digging, boring, and sounding depending on the type of pole and its setting. Sounding involves personnel using a hammer to make sound tests to detect internal decay pockets. A visual inspection is also completed as part of these inspections. Visual inspections look for signs of obvious external damage in the above ground portion of the pole, such as damage from vehicles or woodpeckers.[1107]

Forecast: For the 2025 TY, SCE forecasts $6.494 million for Intrusive Pole Inspections. The forecast for intrusive inspections is based on the number of inspections forecast to be completed in the 2025 TY and the inspection unit cost with a 3.5 percent increase included to account for contractor rate increases. The forecast also includes current vacancies for three full time employees within the program that will potentially be filled prior to TY 2025.[1108] These costs are uncontested.

14.1.4. Pole Remediations

SCE's pole remediation activities include pole replacement, steel stubbing, and wood pole disposal.

[1105] GO 165 defines intrusive pole inspections as "involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading."

[1106] Ex. SCE-02, Vol. 9 at 14.

[1107] Ex. SCE-02, Vol. 9 at 14.

[1108] Ex. SCE-02, Vol. 9 at 16.

Pole Replacements: Pole replacements are identified through a variety of sources but the process for replacing them is generally the same. First, pole replacements are driven by pole loading assessments. These assessments identify poles that are noncompliant that must be replaced within the timeframe for replacements according to GO 95. Under these assessments a pole will be replaced between 72 hours and 36 months.[1109] The Pole Loading Program ended in 2022, but replacements will continue through 2025. Next, after an intrusive pole inspection, the poles identified as needing replacement are prioritized based on the extent of deterioration and are assigned a Remediation Action Code.[1110]

Poles identified through other activities outside of the Intrusive Pole Inspection Program may be submitted to the Deteriorated Pole Program for replacement based on their external condition. If these poles meet the criteria for external decay outlined in the program standard, SCE states that they are prioritized according to the standard for replacement in the Deteriorated Pole Program.[1111]

Next, pole loading calculations (PLC) performed in the course of design work may identify poles that do not meet GO 95 requirements. SCE states that planners perform PLCs as part of day-to-day work when they plan to add new equipment to a pole, such as a transformer, capacitor bank, or conductor wire. SCE states that the planner may perform a PLC on the pole "as-is," in its current state, assuming only the currently attached equipment is in place. However, SCE

[1109] Ex. SCE-02, Vol. 9 at 19.

[1110] Ex. SCE-02, Vol. 9 at 19.

[1111] Ex. SCE-02, Vol. 9 at 20.

testifies that if the pole does not satisfy compliance requirements "as-is," the cost of its replacement is included in the Deteriorated Pole Program.[1112]

Pole Replacements Forecast: SCE states that the 2023-2028 capital expenditure forecast for Pole Replacements is $1.556 billion for distribution and $592 million for transmission and telecommunications.[1113] SCE testifies that the scope forecast is made up of two categories: (1) poles that have already been identified as requiring replacement and will be planned for replacement during the 2023-2028 period; and (2) pole replacements that SCE forecasts will be identified through the activities described above during the 2023-2028 time period.[1114]

Next, when developing its unit cost forecast, SCE states it began analyzing the cost to replace a pole based on historical data from closed work orders; this methodology was used and approved by the Commission in SCE's 2018 and 2021 GRCs. SCE then evaluated other factors that would impact the pole replacement unit cost going forward.[1115]

The base unit cost forecast for the pole replacement includes four components. These components are: (1) base unit costs; (2) environmental unit costs; (3) B-item material costs; and (4) overhead costs.[1116] SCE states that for distribution, SCE determined the 2022 closed work orders were the best representation of a distribution pole's base unit cost. For transmission, SCE

[1112] Ex. SCE-02, Vol. 9 at 20.

[1113] Ex. SCE-02, Vol. 9 at 21-22; Ex. SCE-13, Vol. 9 at 4. Original forecasts of $1.571 billion and $595 million adjusted to reflect recorded 2023 costs.

[1114] Ex. SCE-02, Vol. 9 at 20.

[1115] Ex. SCE-02, Vol. 9 at 26.

[1116] Ex. SCE-02, Vol. 9 at 27.

states base unit costs are more complex and require additional planning, extending over multiple years.[1117] SCE explains that using a 2021 and 2022 closed work order sample was the best representation for transmission, telecommunication, and underbuild base unit costs, as a single year would not be an accurate representation of future costs.[1118]

With respect to the environmental unit costs, SCE states the 2022 closed work order sample did not provide recent known impacts. SCE states it expects to see an increase in wetlands and construction, storm water permitting reviews, and agency fees due to increased and more complex environmental requirements.[1119] For B-item material costs, which includes nuts and bolts and other miscellaneous materials used for pole replacements, SCE based these on 2022 recorded costs.[1120]

SCE then evaluated other factors that would impact the pole replacement unit cost for 2023-2028. SCE states that certain costs are not represented in the historical base and future impacts, including: (1) the program type driving the replacement and the region or grid in which the work is performed; (2) California Department of Transportation Design Standard Decision Document, which is a request for deviation from design standards; (3) the construction resource that replaces the pole; (4) contractor rate increases; (5) pole

[1117] Ex. SCE-02, Vol. 9 at 27.

[1118] Ex. SCE-02, Vol. 9 at 28.

[1119] Ex. SCE-02, Vol. 9 at 28.

[1120] Ex. SCE-02, Vol. 9 at 28. For allocated costs, SCE used a five-year historical record analysis, which aligns with SCE's 2021 GRC for Distribution poles.

material cost increases; (6) contract design rate increases; (7) line and non-line contractor cost increases; and (8) change in material type mix.[1121]

Steel Stubbing: Next, SCE states that some deteriorated poles can be remediated with the installation of a steel stub. SCE states that steel stubbing is a restoration method that extends the life of a deteriorated pole for likely over 15 years. SCE states that steel stub installations are done by a contractor and therefore, the capital cost includes all costs associated with a steel stub installation including design, material, and construction.[1122]

Steel Stubbing Forecast: SCE states that the 2023-2028 capital forecast for steel stubbing is $3.815 million.[1123] The steel stub installation forecast is based on the number of steel stubs identified to be installed, multiplied by the installation unit cost. SCE also states that 2022-unit cost data was not finalized during the development of the steel stub forecast, therefore, the unit costs of $1,510 for distribution and $2,384 for transmission are based on the 2021 recorded costs.[1124]

Wood Pole Disposal: Finally, for wood pole disposals, SCE states that wood poles must be appropriately disposed of to avoid adverse environmental impacts. Poles are treated with chemical preservatives to prevent decay. SCE testifies that since 2006, poles treated with chemical preservatives must be disposed of as hazardous waste materials.[1125]

[1121] Ex. SCE-02, Vol. 9 at 28-31.

[1122] Ex. SCE-02, Vol. 9 at 33.

[1123] SCE's steel stubbing forecast costs are included in the forecasts for Distribution and Transmission Pole Replacement. *See* Ex. SCE-02, Vol. 9, footnote 37 at 34.

[1124] Ex. SCE-02, Vol. 9 at 33.

[1125] Ex. SCE-02, Vol. 9 at 35.

Wood Pole Disposal Forecast: SCE states the 2023-2028 capital forecast for wood pole disposal is estimated to be $25.750 million. SCE states that this estimation is derived by multiplying the number of pole replacements by the disposal unit cost.[1126] The disposal unit cost is determined based on an average of the preceding three years. SCE also testifies that one significant variable that can influence the costs is the geographical location of the poles and the availability of disposal in that specific area.[1127]

Generally, these costs are uncontested but for Cal Advocates' adjustment to SCE's Transmission Deteriorated Pole Replacement 2024 forecast, which we discuss in detail, below.

14.1.5. Joint Pole Credits

The Joint Pole O&M Credit includes the amounts received from joint owners as reimbursement for SCE's pole activities.[1128] SCE states that the TY 2025 forecast for the Joint Pole O&M Credit is ($8.967) million.[1129] SCE states that the forecast for O&M credits from joint owners is based on a three-year recorded average amount for this activity. SCE states that a three-year average is reasonable because the drivers of these credits are largely based on the actions of the Southern California Joint Pole Committee joint owners and are not within SCE's control.[1130] This forecast is uncontested.

[1126] Ex. SCE-02, Vol. 9 at 35-36.

[1127] Ex. SCE-02, Vol. 9 at 36.

[1128] Ex. SCE-02, Vol. 9 at 37.

[1129] Ex. SCE-02, Vol. 9 at 40.

[1130] Ex. SCE-02, Vol. 9 at 41.

The Joint Pole Capital Credit includes amounts received from joint owners purchasing an interest in new poles. For 2023-2025, the Joint Pole Capital Credit forecast is ($255.068) million.[1131] This forecast is uncontested.

14.1.6. Joint Use Pole Management

Under California's nondiscriminatory access rules implemented in D.98-10-058 and amended by D.16-01-046, D.18-04-007, and D.22-10-025, SCE must provide nondiscriminatory access to certain Telecommunications providers to attach to SCE's poles through a license agreement.

SCE's Joint Pole Organization (JPO) is responsible for the execution and administration of agreements to license pole space to other utilities, also referred to as renters.[1132] SCE also states that it participates in the Southern California Joint Pole Committee (JPC) where members may have an ownership interest in each other's poles (including SCE's) to attach their equipment or the equipment of a licensee in their ownership portion of their pole. SCE testifies that JPO manages SCE's relationships with these entities.[1133]

Under the Commission's right-of-way (ROW) rules, renters (or tenants) license space for their attachments within space owned by SCE on its poles. Renters, primarily competitive local exchange carriers and some cable television companies, will execute a license agreement with SCE and then submit their requests to attach to SCE's poles. SCE has over 150 active license agreements with pole renters.[1134]

[1131] Ex. SCE-02, Vol. 9 at 40-42.

[1132] Ex. SCE-02, Vol. 9 at 42.

[1133] Ex. SCE-02, Vol. 9 at 42.

[1134] Ex. SCE-02, Vol. 9 at 42.

Joint Use Pole Management Forecast: The 2025 TY forecast for Joint Pole Operations is $1.145 million. The Joint Pole Operations forecast for labor and non-labor is based on 2022 recorded costs. SCE states that Joint Pole Operations does not anticipate any changes to staffing levels or current operations. SCE states that the $0.086 million increase in 2025 labor is attributable to an adjustment to reflect certain changes made to SCE's employee compensation program.[1135]

Request for Attachments: Next, the Third-Party Attachments Group (TPA), within JPO, is responsible for the technical evaluation of third-party Requests for Access (RFA) applications submitted by renters and Joint Pole Authorizations (JPAs) submitted by joint owners. SCE states that TPA performs the planning review, pole loading, and field verification for all RFAs. TPA approves or denies third-party access to SCE poles or SCE space on jointly owned poles upon verification that the applicant, renter, or owner has fulfilled SCE's requirements and standards for attachments. SCE also testifies that TPA may also identify unauthorized attachments. TPA is responsible for conducting post construction inspections on rental attachments to ensure the attaching entity is within existing compliance standards.[1136]

Request for Attachments Forecast: The 2025 TY forecast for Request for Attachments is $2.617 million and is based on 2022 labor and non-labor recorded costs.[1137] The Request for Attachments group does not anticipate any changes to

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[1135] Ex. SCE-02, Vol. 9 at 45.

[1136] Ex. SCE-02, Vol. 9 at 46.

[1137] Ex. SCE-13, Vol. 9, Table I-1 at 2. Comprised of $1.986 million for Distribution Request for Attachment Inspections and $0.631 million for Transmission Request for Attachment Inspections.

staffing levels or current operations beyond 2022. SCE claims that last year recorded methodology is the most representative forecast due to ongoing operations matching what took place in 2022.[1138] The $0.040 million increase in 2025 is attributable to an adjustment to reflect certain changes made to SCE's employee compensation program.[1139] The forecasted costs for the activities described above are uncontested.

14.2. Parties' Positions

14.2.1. Cal Advocates

Cal Advocates does not oppose SCE's forecasted costs for its Poles O&M. However, Cal Advocates opposes the forecast costs associated with SCE's Transmission Deteriorated Pole Replacement Program.[1140] Cal Advocates recommends that the Commission adopt the following capital costs for Poles Activities: $493.001 million in 2023, $335.522 million in 2024 and $211.816 million in TY 2025. Cal Advocates' recommendation is $0 million less than SCE's request of $493.001 million in 2023, $11.967 million less than SCE's request of $347.489 million in 2024, and $0 million less than SCE's request of $211.816 million in TY 2025. Again, Cal Advocates only adjusts SCE's Transmission Deteriorated Pole Replacement 2024 forecast.[1141]

Cal Advocates testifies that it developed its 2024 recommendation by utilizing SCE's five-year average Transmission Deteriorated Pole Replacement costs from 2018 to 2022.[1142] In support of its methodology, Cal Advocates argues

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[1138] Ex. SCE-02, Vol. 9 at 48.

[1139] Ex. SCE-02, Vol. 9 at 48.

[1140] Cal Advocates OB at 218.

[1141] Cal Advocates OB at 218.

[1142] Ex. CA-04 at 41.

that SCE did not provide the basis for its forecast or supporting documentation to justify its 13 percent increase in 2024, relative to the five-year average of recorded total Transmission Deteriorated Pole Replacement costs. Cal Advocates contends that SCE did not provide any analysis or documentation to justify its significant increase in its Transmission Deteriorated Pole Replacement expenditures in 2024. Cal Advocates states that as a result, it was unable to review and evaluate the bases of SCE's forecasts to determine whether they were reasonable.[1143]

14.2.2. SCE's Rebuttal

For its part, SCE asserts that Cal Advocates' methodology is flawed. SCE asserts that Cal Advocates provides no justification for using a five-year average for only 2024, while subsequently reverting back to SCE's forecast and underlying unit cost methodology for all other years and pole replacement activities.[1144] SCE asserts that arbitrarily proposing a five-year average for only one year without any logical basis is unreasonable.[1145]

14.3. Discussion

First, we authorize and adopt SCE's uncontested Pole O&M and its uncontested Capital Request components. In doing so, we find the uncontested costs reasonable. Next, we turn to the contested area of SCE's Capital Request: Transmission Deteriorated Pole Replacement. We also approve SCE's uncontested proposal to eliminate the PLDPBA.

[1143] Ex. CA-04-E at 44.

[1144] Ex. SCE-13, Vol. 9 at 7-8.

[1145] Ex. SCE-13, Vol. 9 at 8.

The issue before the Commission regarding SCE's Transmission Deteriorated Pole Replacement Program is whether the Commission should adopt SCE's forecasting methodology for 2024 or whether to adopt Cal Advocates' proposed methodology. We adopt SCE's forecasting methodology for the 2024 Deteriorated Pole Replacement Program. SCE's Distribution, Underbuild, and Telecommunications Deteriorated Pole Replacements forecast applies the same methodology as SCE's Transmission Deteriorated Pole Program. SCE's testimony shows that 2024's variance account for time variances, which include: (1) compliance due dates for a specific year; and (2) efficiency opportunities for some poles and project delays for others. Thus, we find SCE's Pole Capital Forecasts reasonable and authorize and adopt these expenditures.

15. Vegetation Management

Vegetation can pose public safety and ignition risks when located in proximity to electrical facilities.[1146] SCE's vegetation management activities in this GRC include: (1) Routine Vegetation Management; (2) the Hazard Tree Program; (3) Structure Brushing; (4) Quality Control; (5) Environmental Support for Vegetation Management; and (6) Vegetation Management Technology Solutions.[1147] For the 2025 TY, SCE requests $641.514 million in O&M expenses to be recorded in the two-way Vegetation Management Balancing Account (VMBA), with either no reasonableness threshold or a reasonableness review

[1146] Ex. SCE-02, Vol. 10A at 15-16 and 62.

[1147] Ex. SCE-02, Vol. 10A at 19 and 104.

threshold of 125 percent.[1148] SCE's 2025 forecast represents an increase of $144.932 million over 2022 recorded expenses.[1149] For 2023–2025, SCE requests $13.518 million in vegetation management capital expenditures to be recorded in the Wildfire Mitigation Plan Memorandum Account (WMPMA).[1150]

Intervenors' positions vary widely. Cal Advocates recommends a TY O&M forecast totaling $523.862 million for SCE's vegetation management activities, based on assertions that SCE did not adequately justify its proposed scope of remote sensing activities and certain forecast vegetation management cost increases. Cal Advocates supports the continuation of SCE's existing two-way VMBA with a 115 percent soft cap.[1151] TURN recommends a TY O&M forecast of $430.408 million for vegetation management, or a $211.106 million reduction to SCE's request.[1152] TURN's alternative forecast is based on two major adjustments to SCE's proposals, with additional reductions to certain programs. First, TURN removes the impacts of SCE's reliance on escalation rates when developing program forecasts. Second, TURN proposes that certain costs for discretionary work be removed. TURN also proposes modifying the VMBA to a one-way balancing account.[1153] EPUC asserts SCE has not justified the approximate 35 percent increase in TY O&M vegetation management expenses

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[1148] SCE OB at 166. Pursuant to the 2021 GRC Track 1 Decision, SCE is currently required to seek recovery of costs in excess of 115 percent of the authorized amount through an after-the-fact reasonableness review application. For costs between 100 percent and 115 percent of the authorized amount, cost recovery may be made through a Tier 2 advice letter filing. (D.21-08-036 at 186).

[1149] Ex. SCE-02, Vol. 10A at 16-18; Ex. SCE-13, Vol. 10, Table I-5 at 6.

[1150] SCE OB at 166.

[1151] Ex. CA-02 at 32-51.

[1152] TURN OB at 154-157; TURN RB at 37.

[1153] TURN OB at 155-156 and 403-405.

compared to the 2022 recorded expense level, and proposes an alternative TY forecast of $611 million based on the average of total vegetation management recorded O&M expenses from 2020-2022 plus escalation.[1154] SBUA does not recommend any specific adjustments to SCE's vegetation management O&M forecasts; however, in the context of the cost overruns SCE experienced for routine vegetation management in 2021 and 2022, SBUA asserts that SCE should endeavor to accurately forecast costs in its GRC application or forego future potential cost overruns.[1155] No intervenor contests SCE's capital expenditure forecast for Vegetation Management Technology Solutions.

A summary of party positions is provided in the table below (constant 2022, $000).[1156] As noted above, EPUC recommends TY O&M expenses totaling $611 million for SCE's entire vegetation management portfolio, but does not provide any program-specific recommendations.[1157]

Table 15-1: Vegetation Management 2025 O&M Forecast by GRC Activity — Summary of SCE, Cal Advocates, and TURN Positions[1158]

Vegetation Management Program Activity	Recorded 2022	2025 TY Forecast		
		SCE's Rebuttal Position	Cal Advocates	TURN
Routine Vegetation Management	401,918	476,165	400,688	314,107

[1154] Ex. EPUC-01 at 36-38; EPUC OB at 29-31.

[1155] SBUA OB at 13-16.

[1156] Ex. SCE-02, Vol. 10A, Table II-7 at 19; Ex. SCE-13, Vol. 10, Table I-3 at 4; SCE OB at 167; Cal Advocates OB at 223; TURN OB at 154-157.

[1157] EPUC OB at 29-31.

[1158] Cal Advocates does not update any of its vegetation management recommendations in response to the revised forecasts presented in SCE's rebuttal testimony.

Vegetation Management Program Activity	Recorded 2022	2025 TY Forecast		
		SCE's Rebuttal Position	Cal Advocates	TURN
Hazard Tree Management Program	34,728	74,406	44,666	25,108
Structure Brushing	10,811	25,766	13,081	No Comment
Quality Control	5,523	12,468	12,718	No Comment
Environmental Support for Vegetation Management	40,317	48,978	48,978	No Comment
Technology Solutions	3,286	3,731	3,731	No Comment
Total Vegetation Management Costs	**496,582**	**641,514**	**523,862**	**430,408**

15.1. Routine Vegetation Management

SCE performs Routine Vegetation Management work to comply with current regulatory requirements and guidance for maintaining clearances around electric assets and to mitigate wildfire risks.[1159] Routine Vegetation Management work is typically conducted within a planned annual cycle along the following stages: (1) an inspection is performed, leading to a prescription for mitigation where necessary; (2) completion of planned mitigation (*e.g.*, tree trimming or removal, weed abatement, and/or fuel management); and (3) quality control by both an internal SCE arborist and an independent contractor to verify mitigations have been completed and conform to required standards. Routine Vegetation Management also includes work that operates on a fluctuating schedule,

[1159] Ex. SCE-02, Vol. 10A at 20. *See*, also, GO 95, California Public Resources Code Section 4292 and Section 4293, and the Federal Energy Regulatory Commission's Reliability Standard FAC-003-4.

commonly in advance of wildfire season in HFRAs, and to mitigate emergent risks.[1160]

15.1.1. Routine Vegetation Management Inspections

SCE's distribution and transmission equipment have traditionally been inspected through ground-based inspections. During a ground-based inspection, an inspector identifies vegetation in need of trimming or removal, considers anticipated vegetation growth over the ensuing 12 months, and investigates any emergent vegetation concerns raised by customers.[1161] In 2023, SCE consolidated all vegetation inspections into a single program, allowing a single contractor to inspect an entire designated area and apply the criteria for all of SCE's vegetation inspection programs.[1162]

Over this GRC period, SCE proposes to transition from primarily ground-based inspections to primarily remote sensing. Remote sensing differs from traditional ground-based inspections in that it relies on sensors to automatically measure the distance between SCE's electrical equipment and nearby vegetation. SCE has operationalized the use of remote sensing in the form of Light Detecting and Ranging (LiDAR) technology to inspect transmission

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[1160] Ex. SCE-02, Vol. 10A at 20-21. HFRAs are based on a combination of historical fire map boundaries, California Department of Forestry and Fire Protection's Fire Hazard Severity Zone maps, and the Commission's approved statewide High Fire Threat District maps. (Ex. SCE-04, Vol. 5, Pt. 1A, footnote 7 at 7; Section 16 (Wildfire Mitigation)).

[1161] Ex. SCE-02, Vol. 10A at 23.

[1162] Historically, SCE would hire different inspection contractors to conduct inspections for its two largest inspection programs: Routine Vegetation Management and the Hazard Tree Program (which includes the Hazard Tree Management Program and Dead & Dying Tree Removal Program). (Ex. SCE-02, Vol. 10A at 33-34; Ex. SCE-13, Vol. 10 at 21-22).

and sub-transmission lines to maintain appropriate vegetation clearances.[1163] SCE also currently uses LiDAR technology in limited instances for distribution lines where the work can be bundled by circuit. In 2022, SCE launched a pilot program to test the use of satellite technology in confirming the accuracy of vegetation clearances and identifying trees near overhead lines. SCE states it plans to continue testing the use of satellite technology as a supplement or alternative to LiDAR.[1164]

For the 2025 TY, SCE forecasts a total of $83.797 million for Routine Vegetation Management Inspections, comprised of $28.084 million for traditional ground inspections and $55.713 million for remote sensing.[1165] SCE's forecast reflects a significant ramp-up of remote sensing inspections to cover SCE's entire service territory (*e.g.*, from 5,000 miles in 2022 to 60,000 miles in 2025). Under SCE's full remote sensing network proposal, ground inspections are performed side-by-side to validate the remote sensing data in 2025, followed by a gradual reduction in the level of ground-based inspections from 2026 through 2028.[1166]

In the event the Commission rejects SCE's full network remote sensing request, SCE recommends an alternative forecast of $74.204 million for Routine Vegetation Management Inspections, comprised of $63.467 million for traditional

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[1163] LiDAR is a surveying inspection method that measures the distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses. Differences in laser return times are used to make digital three-dimensional representations of field conditions at the time of survey. In 2022, SCE inspected approximately 3,700 transmission circuit miles, and 1,600 distribution circuit miles, using LiDAR. (Ex. SCE-02, Vol. 10A at 28; SCE-04, Vol. 5, Pt.3A at 53).

[1164] Ex. SCE-02, Vol. 10A at 27-30 and 35-36; SCE OB at 168.

[1165] Ex. SCE-13, Vol. 10, Table II-7 at 8.

[1166] Ex. SCE-02, Vol. 10A at 18, 30, and 32.

ground inspections and $10.737 million for remote sensing.[1167] SCE's alternative forecast reflects continued use of remote sensing for a small portion of SCE's network while maintaining primary reliance on traditional ground-based inspections.[1168] This alternative forecast also includes changes to SCE's request for seasonal patrol inspections, as discussed below.

SCE uses an itemized forecast methodology for the two Routine Vegetation Management Inspections Program forecasts based on 2022 contractor bids, plus escalation and a time and equipment adder,[1169] as well as the anticipated number of circuit miles and forecast unit cost of $811 per circuit mile for LiDAR inspections.[1170] SCE's full remote sensing inspections forecast assumes traditional ground inspections are 50 percent of 2025 levels in 2026, 35 percent of 2025 levels in 2027, and 20 percent of 2025 levels in 2028.[1171]

15.1.1.1. Parties' Positions

Cal Advocates recommends $18.571 million for remote sensing inspections corresponding to a phased approach to remote sensing (*i.e.*, covering 20,000 circuit miles compared to SCE's proposed 60,000 circuit miles). In addition, Cal Advocates recommends $37.337 million for traditional ground-based

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[1167] Comprised of $63.467 million for Traditional Ground Inspections, $10.737 million for Remote Sensing, and $5.394 million for Seasonal Patrols Inspections. (SCE OB at 169).

[1168] Ex. SCE-13, Vol. 10, Table II-8 at 9 and footnote 33 at 22.

[1169] Ex. SCE-02, Vol. 10A WP at 10.

[1170] SCE's forecast unit cost of $811 per circuit mile for LiDAR inspections includes flight costs, data processing costs, data analysis, project management, and other supporting activities. (Ex. SCE-02, Vol. 10A at 31-33; Ex. SCE-02, Vol. 10A WP at 33).

[1171] Ex. SCE-02, Vol. 10A at 27.

inspections.[1172] Cal Advocates' recommendations are premised on the following arguments: (1) SCE fails to review or provide an evaluation of its LiDAR pilot program to be able to determine if the ramped-up scope of work in 2025 is achievable, more efficient than current processes, and whether the benefits outweigh the costs; (2) the magnitude of SCE's remote sensing proposal is not discussed or evaluated in SCE's 2023–2025 Wildfire Mitigation Plan (WMP); (3) SCE's 2025 TY remote sensing forecast does not phase in the proposed scope of 60,000 miles per year; (4) SCE forecasts a higher cost per mile for remote sensing in the 2025 TY than it recorded in 2022, while remote sensing costs declined from 2021-2022; and (5) the costs for traditional ground inspections have been declining since 2020.[1173]

TURN recommends a 2025 TY forecast of $52.122 million for Routine Vegetation Management Inspections, comprised of $47.122 million for traditional ground inspections and $5 million for remote sensing.[1174] While TURN provides separate forecasts for traditional ground inspections and remote sensing, TURN is neutral as to which type of inspections SCE pursues provided the chosen method "efficiently and effectively identifies the work that needs to be done and that ratepayers are delivered the promised benefits."[1175] TURN's forecast for

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[1172] Cal Advocates' TY O&M forecast for traditional ground inspections is based on SCE's initial position in direct testimony. In rebuttal testimony, SCE adjusted its TY O&M forecast for traditional ground inspections (assuming full remote networking) to $28.084 million to reflect savings from SCE's Operational Excellence efforts. (Ex. CA-02, Table 2-16 at 37; Cal Advocates OB at 225; Ex. SCE-13, Vol. 10 at 4).

[1173] Ex. CA-02 at 37-43; Cal Advocates OB at 224-227.

[1174] Ex. TURN-09E at 14; Ex. SCE-13, Vol. 10, Appendix A at A17-A20.

[1175] TURN OB at 158. While TURN's initial position was that remote sensing should continue as a pilot program, in briefs TURN accepts SCE's assertion that remote sensing is sufficiently mature to deploy on a wide scale. (Ex. TURN-09E at 12; TURN OB at 157-162; TURN RB at 38).

traditional ground inspections is based on 2022 recorded costs plus five percent annual escalation based on Bureau of Labor Statistics historical inflation rates.[1176] TURN does not explain how it calculated the proposed $5 million in TY O&M expenses for remote sensing.[1177] TURN's recommendation is premised on the following points: (1) SCE's total TY O&M request of $85.146 million for Routine Vegetation Management Inspections is more than double the recorded costs for traditional ground inspections in 2022; (2) SCE's proposal will charge ratepayers for both ground and remote sensing inspections with no timeline for when/if traditional ground inspections will be completely phased out, or how SCE determined the appropriate amount of ground inspections required; (3) while some redundancy may be required to confirm the effectiveness of LiDAR, full scope redundancy is not; (4) SCE has not stated how it will allocate the costs of LiDAR to separate programs within compliance and non-compliance activities;[1178] and (5) SCE's alternative forecast relies on an inflated 15 percent escalation rate, compared to the actual average inflation rate of five percent between 2022–2024 and the approximately six percent increase from completed contract negotiations in Q4 2023.[1179]

Citing the vegetation management cost overruns SCE incurred in 2021–2022, SBUA asserts that SCE should endeavor, to the greatest extent possible, to accurately forecast costs in this proceeding where a wide variety of parties are engaged. SBUA supports recent improvements made to SCE's vendor

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[1176] TURN OB at 156; SCE RB at 53.

[1177] SCE-13, Vol. 10, Appendix A at A19-A20; Ex. TURN-09 at 12-14.

[1178] Ex. TURN-09E at 12-14; TURN OB at 157-162.

[1179] The actual inflation rates over 2022-2024 were 6.2 percent, 4.8 percent, and four percent. (TURN OB at 161-162).

management practices, including pre-negotiated unit prices for all areas as well as SCE's policy of prohibiting a single contractor from having more than 30 percent market share.[1180] At the same time, SBUA questions SCE's ability to ramp up remote sensing to cover SCE's full network while significantly reducing traditional ground inspections.[1181] SBUA also asserts SCE's near-term vendor labor costs are dramatically understated, since SCE's proposed 15 percent escalation factor does not consider possible unionization.[1182] SBUA recommends SCE be required to present less optimistic forecasts in this GRC with different unionization scenarios and conduct a market study to determine how SCE's vendor employees' benefits and salary compare with competitor employers.[1183]

SCE asserts the potential benefits of remote sensing and its various applications are vast, particularly in terms of improving the accuracy of inspections, reducing costs, and improving quality. For example, SCE states remote sensing may enable automatic prescriptions in the future, which could lead to shorter inspection times, more targeted inspections, and other beneficial outcomes that SCE asserts could help lower overall inspection costs and/or shorten inspection cycles. Further, SCE states advancements in other technologies, such as satellite imagery, could provide significant additional data at a lower cost,[1184] while the digital data may be used for asset analytics and

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[1180] Ex. SBUA-01 at 12-13; RT, Vol. 13 at 1357-1369; SBUA OB at 13-15.

[1181] Ex. SBUA-01 at 11-12.

[1182] Some of SCE's vendor vegetation workforce is not unionized, however, unionization negotiations are presently underway. (RT, Vol. 13 at 1370:15-1371:9).

[1183] SBUA OB at 14-16.

[1184] For example, hyperspectral satellite imaging can be used to identify vegetation health, density, and species. (SCE OB, footnote 1022 at 168).

other advanced technology efforts. In contrast, SCE asserts traditional ground-based inspections offer fewer advancements and continue to expose SCE to fluctuations in the labor market.[1185]

In response to Cal Advocates and SBUA, SCE asserts it has substantial experience with remote sensing technology for inspections, having operated LiDAR for transmission circuits since 2019 and for distribution circuits since 2022, and that preparations are on target to meet SCE's service area-wide annual remote sensing inspection schedule.[1186] Further, SCE asserts it clearly signaled its intention to implement full network remote sensing in its 2023–2025 WMP, while the WMP and GRC have different review processes and contain content that is often not directly comparable.[1187] SCE also asserts that completing remote sensing and traditional ground inspections for the full network over a single inspection cycle is necessary for ground inspectors to validate the remote sensing data, and to develop a reliable and verified digital inventory baseline and predictive models. In contrast, SCE asserts Cal Advocates' proposed phased approach would require SCE to design and execute a complex, inefficient, and possibly unfeasible multi-year work plan to both complete its required annual inspections and ensure remote sensing data verification.[1188]

In response to TURN, SCE asserts its proposed 15 percent escalation factor reflects initial bids in the new contract cycle at the time SCE prepared its GRC application, and is necessary to promote retention and upskilling in the face of

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[1185] Ex. SCE-13, Vol. 10 at 15-16; RT, Vol. 13 at 1354:5-20; SCE OB at 168.

[1186] Ex. SCE-13, Vol. 10 at 13-15.

[1187] Ex. SCE-13, Vol. 10 at 16-18.

[1188] Ex. SCE-13, Vol. 10 at 18-20.

stiff labor market competition as well as the likelihood of a unionized workforce in SCE's service territory. Further, SCE asserts its escalation assumptions have largely materialized as predicted; following its most recent vegetation management contract solicitation in the fall of 2023, SCE states it observed estimated increases ranging from six percent to greater than 60 percent under various vegetation management programs compared to prior contract cycles.[1189] While SCE states its full remote sensing forecast incorporates an "aggressive" ramp-down of traditional ground inspections beginning in 2026, SCE testifies it would not be feasible or prudent to completely eliminate traditional ground-based inspections since some areas (such as detailed hazard tree assessments, dense tree overhangs, or data anomalies) will continue to require ground inspections even after full network remote sensing.[1190]

Concerning SBUA's recommendation for SCE to conduct a market study to estimate the magnitude of potential vegetation management cost increases, SCE states SBUA's recommendation is untimely as it is provided for the first time in opening brief. However, SCE also asserts it has identified, as part of this proceeding, multiple exogenous factors that could impact vegetation management costs, and that SCE's two-way VMBA is designed to accommodate these uncertainties.[1191]

Lastly, SCE asserts intervenors fail to appreciate the interdependencies between the remote sensing and ground-based inspections forecasts. By reducing the remote sensing forecast volume, while maintaining SCE's original

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[1189] Ex. SCE-13, Vol. 10 at 21; SCE RB at 52-54.

[1190] Ex. SCE-02, Vol. 10A at 35; SCE RB at 58.

[1191] SCE RB at 67.

proposed forecast for traditional ground-based inspections, SCE asserts that Cal Advocates' proposal would leave SCE exposed and underfunded.[1192] Similarly, SCE asserts TURN's proposal to limit traditional ground inspections to historical inflation rates, while keeping remote sensing at a pilot level, disregards operational realities and market pressures and provides no realistic path for SCE to adopt remote sensing technologies more broadly. As discussed below, SCE also highlights the interdependencies between its proposed forecasts for remote sensing and ground-based inspections and its forecasts for Seasonal Patrols, AOC, and Emergent Work.[1193]

15.1.1.2. Discussion

This decision approves $62.435 million in TY O&M expenses for Routine Vegetation Management Inspections, including $34.459 million for traditional ground-based inspections and $27.976 million for remote sensing. The approved forecast is expected to provide sufficient funding for SCE to phase in remote sensing inspections covering approximately half of SCE's entire service network (*e.g.*, 30,000 circuit miles) over this GRC period, with additional funding for ground-based inspections to cover the remainder of SCE's network and to verify the accuracy of remote sensing data. As discussed below, while we agree remote sensing has the potential to deliver significant long-term benefits, we find it prudent and in ratepayers' best interest to approve funding to support a phased transition to full remote sensing. SCE is not prohibited from conducting additional remote sensing inspections beyond the forecast level approved in this

[1192] SCE OB at 170.

[1193] SCE OB at 172-173.

decision provided it is able to deliver the projected benefits of the additional remote sensing inspections without increasing rates.

This decision supports a phased transition to remote sensing for several reasons. First, while the purported benefits and efficiency gains from remote sensing appear promising, the magnitude of benefits and overall cost savings from remote sensing are largely speculative. SCE's arguments for full remote sensing in this proceeding hinge on "potential" benefits and prospective use cases, rather than verifiable documentation and/or studies of past remote sensing inspections, while there is a stark difference between SCE's historic level of remote sensing and full remote sensing across SCE's entire 60,000-mile network.[1194] Rather than implementing a complete overhaul of SCE's current Routine Vegetation Management Inspections Program based on speculative benefits, we find it prudent to take a more cautious approach that will allow SCE to continue to explore and validate remote sensing as a substitute for traditional ground inspections at a much larger scale.

Second, contrary to SCE's assertions, it is not clear whether a phased approach will reduce the efficiencies and benefits of SCE's transition to remote sensing, and in some instances a phased approach may result in additional benefits. SCE's full remote sensing forecast in this proceeding is based on contracted LiDAR work;[1195] however, SCE indicates it is considering conducting LiDAR processing and data acquisition work in-house and has been piloting the

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[1194] Between 2019 and 2022, SCE used LiDAR technology to survey approximately 6,500, 1,500, 3,000, and 5,000 miles, respectively, covering approximately three to 11 percent of SCE's network. (Ex. SCE-02, Vol. 10A at 30).

[1195] SCE's full network remote sensing forecast unit cost of approximately $811 per circuit mile for LiDAR includes flight costs, data processing costs, data analysis, project management, and other supporting activities. (Ex. SCE-02, Vol. 10A at 33).

use of satellite imagery for remote sensing, both of which could lead to reduced costs and/or improved overall effectiveness.[1196] Rather than implementing an all-in remote sensing approach in 2025, with additional potential adjustments and associated, incremental costs in subsequent years, a phased approach could lead to additional cost savings and efficiencies as SCE continues to explore and integrate more cost-effective remote sensing technologies and approaches. Additionally, a phased approach may help further inform whether full scope redundancy is necessary to validate all remoting sensing data, or whether validation can be accomplished through smaller, more cost-effective, sample sizes. In its next GRC filing, SCE is directed to present data on the accuracy of its remote sensing inspections data and provide recommendations concerning the level of ground-based inspections and data validation required for both ongoing and new remote sensing inspections.

SCE asserts a phased approach to remote sensing would "require, at minimum, two or three cycles at additional cost for Traditional Ground Inspections, while utilizing partial network remote sensing data to develop the digital inventory baseline."[1197] While there will be some costs associated with the continuation of traditional ground inspections under a phased remote sensing approach, for the reasons discussed above, we believe it is prudent to fully evaluate the potential benefits, cost savings, and accuracy of remote sensing technologies prior to full network implementation. Further, as discussed below, the approved forecast for traditional ground inspections in this decision reflects an immediate 40 percent reduction in ground inspections from 2026–2028,

[1196] Ex. SCE-02, Vol. 10A at 33; Ex. SCE-13, Vol. 10 at 13; RT, Vol. 13 at 1351-1354.

[1197] Ex. SCE-13, Vol. 10 at 18.

corresponding with the ramp-up in remote sensing inspections. Compared to SCE's glidepath for reducing traditional ground inspections under full network remote sensing, this immediate 40 percent reduction results in less overlap between the two inspection types during the post-test year periods. Further, while this decision provides sufficient funding to validate the initial round of remote sensing data through ground-based inspections, there is limited record in this proceeding concerning the level of data SCE needs to develop the digital inventory baseline, how SCE intends to maintain and validate the digital inventory baseline over time (especially as new remote sensing technologies are introduced), and the development of program metrics to track the performance and success of the remote sensing program. In its next GRC filing, SCE is instructed to provide additional information addressing each of these issues.

Lastly, SCE broadly asserts a phased remote sensing approach would require SCE to design and execute a complex, inefficient, and possibly unfeasible work plan.[1198] SCE does not provide any evidence to support its assertion that a phased approach is unworkable, and it is not clear, based on the evidence presented in this proceeding, why verification of data under a phased approach would be more complex than full network remote sensing since both approaches would require timely verification of remote sensing data in coordination with annual ground-based inspection schedules and regulatory compliance requirements. We note that a phased approach also addresses intervenor concerns regarding SCE's ability to quickly ramp up remote sensing work.

For all the above reasons, we authorize $27.976 million in TY O&M expenses for SCE to phase in remote sensing inspections over approximately half

[1198] Ex. SCE-13, Vol. 10 at 18.

of its service territory. The approved remote sensing amount utilizes SCE's forecast methodology, including a unit cost of $811 per circuit mile plus adjustments for support activities and compensation changes, but is based on 30,000 circuit miles rather than SCE's proposed 60,000 circuit miles. We note that SCE's remote sensing forecast unit cost is significantly higher than SCE's recorded 2022 costs for both LiDAR ($631 per circuit mile) and satellite ($220 per circuit mile), and reflects additional anticipated work associated with: (1) data gathering and modeling; (2) data integration; (3) project management and execution; (4) project enhancements; and (5) consultant support.[1199] In its next GRC application, SCE is instructed to explain how the remote sensing expenses approved in this decision were spent utilizing the work categories above along with any other relevant cost categories.

This decision also authorizes $34.459 million in TY O&M expenses for traditional ground inspections. The approved forecast amount is based on SCE's forecast methodology, but assumes traditional ground inspection costs will be reduced to 60 percent of 2025 ground inspection cost levels in 2026–2028, corresponding to the ramp-up of remote sensing work plus additional expenses to conduct ground inspections at certain locations. Following full network remote sensing, SCE indicates ground inspections will still be necessary in certain locations (for example, to identify hazard tree conditions, conduct inspections at locations that are blocked from aerial views, and respond to emergency conditions), and forecasts 20 percent of 2025 ground inspection cost levels in 2028.[1200] Since the remote sensing budget approved in this decision is

[1199] Ex. SCE-02, Vol. 10 WP at 5 and 35.

[1200] Ex. SCE-02, Vol. 10A at 23 and 27.

expected to cover half of SCE's network, we assume a budget for 10 percent of 2025 ground inspection costs will still be needed in areas inspected by remote sensing. As noted above, in its next GRC filing SCE is directed to present data on the accuracy of its remote sensing inspections data as well as recommendations concerning the level of ongoing ground-based inspections.

The authorized TY amount for traditional ground inspections also includes a six percent escalation factor in 2024 and a seven percent escalation factor in 2025. We find SCE has largely failed to justify its proposed 15 percent escalation factor. As noted by TURN, SCE's arguments that it observed a 20 percent increase in the initial 2022 inspection contract bids, and that a higher escalation factor is needed for retention and upskilling, are contravened by the fact that SCE entered into a new contract cycle in January 2024 reflecting an approximate six percent increase over the 2023 contracts.[1201] SCE points to recent union negotiations with PG&E that provide wage escalation of 3.75 percent per year plus an additional "in-lieu of benefits" percentage, but fails to present any evidence comparing how the specific wages offered by PG&E compare to the wages approved in SCE's most recent contract cycle. Similarly, SCE and SBUA highlight that SCE did not consider possible unionization in developing its proposed escalation factor; however, neither party presented evidence demonstrating the potential magnitude of cost increases following possible unionization, nor did SCE perform a labor market study analyzing the expected cost impact of unionization on the vegetation management vendor workforce. Based on these findings, we approve a six percent escalation factor in 2024,

[1201] SCE OB at 171; TURN RB at 39.

reflecting the outcome of SCE's 2023 contract negotiations, plus a modest increase in 2025 to account for potential unionization.

We decline to adopt the alternative inspection forecasts presented by Cal Advocates and TURN. As argued by SCE, Cal Advocates reduces the volume of remote sensing inspections without making corresponding changes to SCE's original proposed forecast for traditional ground inspections. Since SCE's proposed forecast for traditional ground inspections is based on the level of remote sensing inspections, Cal Advocates' proposal would leave SCE underfunded. TURN states it is neutral as to which type of inspections SCE pursues provided ratepayers are delivered the promised benefits;[1202] however, TURN fails to provide any calculations or explanation for how it derived its proposed $5 million remote sensing forecast. We believe the potential benefits from remote sensing warrant further exploration and utilize a forecast methodology that reflects the level and type of activities to be performed.

15.1.2. Routine Line Clearing

SCE's largest vegetation management program consists primarily of compliance-based line clearing activities across SCE's distribution and transmission networks. Under the Routine Line Clearing Program, SCE endeavors to prevent vegetation from encroaching into its electrical assets by maintaining respective clearance zones in compliance with FERC and Commission-jurisdictional regulatory requirements. SCE's Routine Line Clearing Program also includes expanded line clearing work, which SCE begin in 2019 to "achieve the expanded recommended clearance distances set forth in the

[1202] TURN OB at 158.

HFTD [High Fire Threat District] Decision and Appendix E of GO 95, Rule 35."[1203]

SCE forecasts $344.159 million in TY O&M expenses for Routine Line Clearing activities. SCE utilizes an itemized methodology for its TY forecast. For its forecast volume of work, SCE applies 790,000 mitigations (750,500 trims and 39,500 removals) based on the average of the 2021 recorded and 2022 annualized volumes. For the unit cost, SCE applies calculated blended unit costs of approximately $300 and $1,600 for trims and removals, respectively.[1204] SCE's average unit costs incorporate weighting by 2022 vendor volume for the respective unit rates and time and expense rates, allocation for adder costs and auxiliary work supporting mitigation (*e.g.*, roaming, specialized equipment, late release, traffic control, environmental coordinators, and customer coordinators),[1205] and assignment of costs by distribution and transmission assets.[1206] SCE also applies a cost escalation of four percent to the 2022 baseline unit rate to reflect the extension of 2022 contracts through year-end 2023, and a 10 percent market escalation rate in 2024 to reflect the new contract cycle.[1207]

[1203] The HFTD Decision refers to D.17-12-024. (Ex. SCE-02, Vol. 10A at 40-41).

[1204] Ex. SCE-02, Vol. 10A at 47.

[1205] Roaming support is a service whereby contractors provide mitigation assistance outside of their service territory; specialized equipment is utilized to support rural areas where geographic conditions and agency restrictions require enhanced sensitivity and/or emerging technologies; late release refers to mitigations previously placed on environmental hold for significant periods of time, while the rest of the area proceeds with timely mitigation; third-party traffic control may be necessary based on geographic restrictions or to maintain the safety of crews; environmental coordinators perform additional scheduling and coordination of environmentally affected work; and customer coordinators perform various work related to customer contacts and obtain approval of prescribed mitigation work. (Ex. SCE-02, Vol. 10A at 48).

[1206] SCE OB at 173.

[1207] Ex. SCE-02, Vol. 10A at 48-49; Ex. SCE-13, Vol. 10 at 24-25.

Lastly, SCE's forecast includes anticipated operational savings from implementation of the Arbora work management tool,[1208] as well as a reduction in Routine Line Clearing work due to SCE's Targeted Undergrounding (TUG) Program.[1209]

15.1.2.1. Parties' Positions

Cal Advocates recommends $307.800 million in O&M expenditures for Routine Line Clearing, or a $36.359 million reduction to SCE's request. Cal Advocates' recommendation incorporates SCE's forecast Routine Line Clearing volume but utilizes the 2022 recorded cost per remediation rather than SCE's blended unit costs. Cal Advocates states its forecast accounts for the downward trend in SCE's Routine Line Clearing costs over the 2020–2022 timeframe.[1210]

TURN recommends $213.776 million in TY O&M expenses for Routine Line Clearing, or a $130.383 million reduction to SCE's request. TURN's alternative forecast utilizes a market escalation factor of two percent (compared to SCE's proposed escalation factor of 10 percent) based on Federal Reserve Inflation Target Rates, and excludes $8.347 million TURN associates with expanded line clearance work.[1211] TURN provides the following arguments in support of its forecast: (1) SCE's vegetation management request must be considered in the context of its extensive covered conductor deployment and

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[1208] As discussed elsewhere, Arbora is a vegetation management software tool used to integrate and manage SCE's vegetation-related programs and activities. (Ex. SCE-02, Vol. 10A at 105).

[1209] SCE's Targeted Undergrounding Program is addressed in Section 16 (Wildfire Mitigation).

[1210] For its Routine Line Clearing activity, SCE recorded $378.603 million in 2020, $348.807 million in 2021, and $328.564 million in 2022. (Ex. SCE-13, Vol. 10, Table I-5 at 6; Ex. CA-02 at 43-45; Cal Advocates OB at 227-229).

[1211] TURN OB at 162, 164, and 167.

other wildfire mitigation measures;[1212] (2) SCE's forecast is premised on historical costs for expanded line clearance deep trim costs, which were presented as temporary in SCE's 2021 GRC;[1213] (3) SCE's expanded line clearance activities are discretionary, since they are beyond the required minimum distances set forth in GO 95, Rule 35;[1214] (4) SCE's expanded line clearance work is not cost-effective, as demonstrated by the program's low RSE score of 4 (compared to the 125,431 RSE for Routine Line Clearing otherwise), and cost-benefit ratio of 0.1;[1215] (5) in its review of SCE's 2022 RAMP submission, the Commission's Safety and Enforcement Division (SED) recommends that risk modeling be conducted for routine vegetation management activities to determine if the Commission should reassess associated compliance requirements; (6) SCE should be required to separately track compliance and non-compliance costs; and (7) consistent with its position on Routine Vegetation Management Inspections, TURN asserts SCE's proposed 10 percent escalation rate is unreasonable given inflation targets are

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[1212] *See* Section 16 (Wildfire Mitigation) for additional information concerning SCE's covered conductor deployment.

[1213] In its 2021 GRC, SCE provided a distribution trim and tree removal forecast which included cost premiums for "initial deeper trims." SCE stated that once "the initial deeper trims are complete in 2019–2020, trimming activities are expected to decrease in 2021 because there is less effort involved in maintaining the already established trims." By including expanded line clearing with no cost differential between deeper trims and maintenance rates in this GRC, TURN asserts that SCE absorbs the otherwise inappropriate historical data into the TY 2025 forecast for Routine Line Clearing. (Ex. TURN-09E at 6-7).

[1214] In testimony, TURN refers to Expanded Line Clearing and the Hazard Tree Management Program as "discretionary" and "non-compliance" activities; in briefs, TURN only refers to these activities as "discretionary." (Ex. TURN-09E at 7, 9, and 13; TURN OB at 40, 156, and 163).

[1215] As discussed elsewhere, RSE is calculated by dividing the present value of the risk reduction of a mitigation by the present value of the cost to implement the mitigation. RSE expresses the cost-effectiveness of an activity that reduces risk. (Ex. TURN-04 at 2).

two percent and actual inflation rates over 2022–2024 were, on average, five percent.[1216]

SCE asserts Cal Advocates' use of the 2022 average cost per remediation is too low and should be rejected for the following reasons: (1) unlike SCE's itemized blended cost forecast, Cal Advocates' use of an average cost-per-remediation does not delineate between trims and removals; (2) SCE experienced relatively favorable conditions for Routine Line Clearing Program in 2022, compared to other years, making it an unrealistic forecast basis for the 2025 GRC period; (3) Cal Advocates' assumption of a continued decline in costs is based on limited evidence using a short three-year sample size; and (4) SCE's contractual rates have increased significantly since 2022.[1217]

SCE asserts TURN's escalation rate is unrealistic and relies on incorrect assumptions concerning the nature and impact of expanded line clearing, resulting in an untenable funding amount. SCE's position is premised on the following arguments: (1) expanded line clearing is necessary to comply with minimum vegetation clearance standards in GO 95 and SCE's obligations under its WMP; (2) while covered conductor may add protection to circuits for grow-in and limited fall-in ignition risk, it does not reduce the chances of heavy tree limbs bringing down covered conductor or help prevent repeated vegetation contact that could potentially shorten the life of the protective covering; (3) TURN's focus on RSE scores fails to consider other risk drivers and consequences, including the significant decrease in outages associated with

[1216] Ex. TURN-09E at 4-8; Ex. TURN-804 at 32; RT, Vol. 13 at 1384:8-13; TURN OB at 162-167; TURN RB at 40-41.

[1217] Ex. SCE-12, Vol. 10 at 24-27; SCE OB at 174-175.

vegetation-caused events since the advent of expanded line clearing;[1218] (4) TURN relies on an incorrect and outdated forecasting assumption from SCE's 2021 GRC, which causes TURN to inflate the number of Expanded Line Clearing trims and assign them outsized cost impacts; (5) since deeper trim rates do not exist in SCE's current contracts with its trimming vendors, any expanded line clearance volume is priced at the standard maintenance trim rate and SCE would incur the same costs regardless of the clearance distance achieved; and (6) SCE's 10 percent escalation rate better reflects ongoing labor market pressures, uncertainties, and recently executed vegetation management contracts, while the Federal Reserve target is an aspirational policy metric that does not account for factors specific to the utility industry or vegetation management activities.[1219] Finally, SCE asserts that TURN's use of the term "non-compliance" is misleading, since both expanded line clearance and the Hazard Tree Management Program (discussed below) help satisfy SCE's obligations under GO 95 and Pub. Util. Code Section 8386(a).

15.1.2.2. Discussion

We authorize $284.221 million in TY O&M expenses for Routine Line Clearing. The authorized amount utilizes SCE's forecast methodology and assumptions as presented in direct and rebuttal testimony, with adjustments to the Routine Line Clearing unit cost, the 2024 market escalation rate, and the associated cost savings from SCE's TUG capital spending program.

[1218] SCE reports an overall 51 percent reduction in the number of Tree-Caused Circuit Interruptions (TCCI) in recent years, based on a comparison of the average of annual TCCIs between 2015–2019 and TCCIs in 2022. SCE's TCCI data includes grow-in, blow-in, and fall-in vegetation events, and excludes human-caused and no cause/not tree related recorded events. (Ex. SCE-02, Vol. 10A at 15).

[1219] SCE OB at 173-178.

Based on the record of this proceeding, this decision finds it reasonable for SCE to continue to maintain expanded line clearances. We reach this conclusion for the following reasons: first, SCE's expanded line clearing work is consistent with D.17-12-024 and within the authority granted pursuant to Appendix E of GO 95, Rule 35. Citing the substantial public safety benefits of keeping bare line conductors clear of vegetation, in 2017 the Commission increased the recommended time-of-trim clearances for circuits located in High Fire-Threat District (HFTD) locations.[1220] SCE's expanded line clearing work is specifically designed to comply with Commission guidance regarding time-of-trim clearances in high fire-threat locations.[1221]

The minimum recommended time-of-trim clearances in D.17-12-024 are based on potential vegetation contact with bare line conductor,[1222] and were adopted prior to the deployment of covered conductor and other advanced technologies in SCE's HFRAs.[1223] At the time of this decision, the Commission has not revised or updated the minimum recommended clearances in GO 95 to account for the deployment of covered conductor. Moreover, the record of this proceeding demonstrates that covered conductor does not, by itself, completely protect circuits in the case of a tree fall-in or branch blow-in during heavy wind conditions, meaning expanded line clearing can help address a particular risk

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[1220] The recommended time-of-trim clearances in HFTD locations are in addition to the minimum clearances required during the period between trims. (D.17-12-024 at 100-102; Appendix E of GO 95, Rule 35).

[1221] Ex. SCE-02, Vol. 10A at 15 and 38-39; Ex. SCE-13, Vol. 10 at 33-34; RT, Vol. 13 at 1382:14-1385:10.

[1222] D.17-012-024 at 100.

[1223] *See* Section 16 (Wildfire Mitigation) for further information concerning SCE's covered conductor deployment to date.

driver regardless of whether a circuit consists of bare wire or covered conductor.[1224] TURN points to the stand-alone risk reduction from fast curve settings,[1225] which are expected to be deployed on a majority of SCE's HFRA circuits and may be combined with covered conductor; however, the record of this proceeding is unclear on the incremental risk reduction benefit of combining fast curve settings with covered conductor.[1226] In addition to fast curve settings, there are significant benefits of covered conductor when combined with Rapid Earth Fault Current Limiters (REFCLs) and spacer cable, which SCE states can approximate the effectiveness of undergrounding.[1227] While the combination of these technologies appears capable of addressing the same risk drivers being mitigated through expanded line clearing, there is limited deployment of REFCL combined with covered conductor in SCE's service territory.[1228] Given its limited deployment, and in consideration of the other findings below, we see no reason

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[1224] SCE reports that covered conductor can help prevent ignition during a wire down event; however, broken conductors and conductors with damage that exposed the underlying metal have the potential for ignition. (Ex. SCE-04, Vol. 5, Pt. 2A at 40-42; Section 16 (Wildfire Mitigation)).

[1225] Fast curve settings increase the speed with which a relay reacts to most fault currents. (Ex. SCE-04, Vol. 5, Pt. 2A at 86).

[1226] During evidentiary hearing, SCE's witness testified that the incremental benefit of fast curve combined with covered conductor and REFCL is unknown (RT, Vol. 10 at 923:20-925:21; TURN OB at 170; SCE RB at 74). However, in an MGRA data request response, SCE estimates that fast curve setting provide an incremental ignition reduction of 1 percent over covered conductor plus REFCL. (Ex. MGRA-01E, Appendix B, Data Request Set MGRA-SCE-007).

[1227] REFCLs are a group of technologies that can detect ground faults and rapidly reduce the fault current should a ground fault occur, thereby reducing the possibility of ignitions from faults. SCE witness Fugere testified that REFCL is more sensitive than fast curve and can de-energize circuits more quickly. (Ex. SCE-04, Vol. 5, Pt. 2A at 77 and 88; RT, Vol. 10 at 981; SCE RB at 74-75 and 79).

[1228] Ex. SCE-04, Vol. 5, Pt. 2A at 74-81.

to restrict funding for SCE to comply with the Commission's minimum recommended vegetation clearance distances at this time.

Second, SCE has already conducted deeper trims to achieve expanded line clearances and is now largely focused on maintaining the expanded line clearances that have already been achieved.[1229] As argued by SCE, if vegetation were allowed to grow back to previous trim distances, the risk reduction gained from extending trims to the expanded distances would be lost. The RSE calculation for Expanded Line Clearing does not fully capture this impact. The relatively lower RSE and cost-benefit scores for this activity are also due, in part, to SCE's use of a more conservative modeling approach for the level of risk reduction.[1230]

SCE's expanded clearing program also includes some deeper trims beyond the Commission's minimum recommended time-of-trim clearance.[1231] As SCE witness Ohanian explained during evidentiary hearings, there are certain fast-growing trees in SCE's tree inventory that can grow 15–20 feet each year. For these trees, SCE's trimming crews may go beyond the recommended 12 feet time-of-trim distance for distribution circuits in HFTD locations.[1232] Appendix E of GO 95 allows utilities to determine and apply additional appropriate clearances beyond the established recommended minimums based on a variety of factors, including vegetation growth rate.[1233] Since these trees can grow beyond the Commission's recommended clearance distance in a year, and may

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[1229] SCE OB at 176.

[1230] Ex. SCE-02, Vol. 10A at 44; Ex. SCE-13, Vol. 10 at 35-36.

[1231] SCE RB at 56.

[1232] RT, Vol. 13 at 1384:3-17.

[1233] *See* GO 95, Rule 35, Appendix E at E-2; D.17-12-024, Appendix A at A-34.

even violate the Commission's minimum required clearance distance between trims, it is reasonable for SCE's crews to incorporate local knowledge and perform deeper trims as necessary.

Finally, it is uncontested that expanded line clearing has been effective at reducing TCCIs. TURN's argument that only a limited number of TCCIs have led to ignitions is devoid of any risk assessment and ignores the fact that a single ignition event can have catastrophic consequences.

Notwithstanding the discussion above, we make three adjustments to SCE's Routine Line Clearing forecast. First, we find SCE has failed to justify the reasonableness of its blended unit cost methodology for trim work. SCE identifies the enactment of SB 247, costs pressures of contractual rate increases, and expanded line clearing performed in response to D.17-12-024 as the three main drivers that have increased Routine Line Clearing costs since 2018 and 2019.[1234] Importantly, and as highlighted TURN, the cost premiums for initial deeper trims that were included in SCE's 2021 GRC to achieve expanded line clearances were intended to be temporary.[1235] While SCE confirms it will largely be maintaining expanded line clearances that have already been achieved over this GRC period,[1236] SCE's use of a single blended unit trim cost does not enable parties or the Commission to whether the cost premiums for deeper trims have declined over time. Since SCE's blended unit cost is based on recent contracts, SCE asserts it will incur the same trim costs regardless of whether the contractor

[1234] SCE RB at 56.

[1235] Ex. TURN-09E at 6-7.

[1236] SCE RB at 56.

achieves clearance distances of 6 feet or 12 feet.[1237] However, the Commission has not reviewed SCE's recent vegetation management contracts for reasonableness; therefore, the fact that SCE's forecast is based on recent contracts does not, by itself, mean that the blended unit trim rate is reasonable.

As stated by TURN, it is difficult to determine with specificity exactly how the workload impacts of the deep trims impacted current contract prices.[1238] While TURN's proposed disallowance relies on forecasting assumptions from SCE's 2021 GRC, given the limited record on how deep trims impacted current contract prices, we find TURN's proposed adjustment provides a reasonable estimate of the unit costs without the upward influence of "temporary" deeper trim costs. Moreover, since this decision authorizes SCE to continue to track vegetation management costs in the two-way Vegetation Management Balancing Account (*See* Section 15.8 (Vegetation Management Balancing Account)), SCE will have the opportunity to seek future recovery of any recorded vegetation management costs that exceed the amounts authorized in this decision. Adjusting SCE's workpapers to reflect TURN's proposed unit cost for trims results in a reduction of $53.701 million to SCE's forecast.[1239]

Second, we find SCE has not sufficiently justified its proposed 10 percent escalation rate, and instead adopt a four percent escalation rate in 2023 and a 7.5 percent escalation rate in 2024. As noted by TURN, the most recent round of Routine Line Clearing contracts have now been completed and the actual

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[1237] Ex. SCE-13, Vol. 10 at 28-30; SCE OB at 176.

[1238] TURN OB at 166.

[1239] Ex. SCE-02, Vol. 10C WP at 2-5; Ex. SCE-13, Vol. 10C, Appendix A at A39.

amounts are known.[1240] The four percent escalation over 2022 contractual trim and removal unit and time and expense (T&E) rates occurred in the extension of the contracts into 2023, with an effective end date of December 31, 2023.[1241] For 2024, SCE reports the average standard maintenance trim rates for Routine Line Clearing vendors were approximately 7.1 percent higher than 2023 rates as of May 1, 2024,[1242] while SCE observed a 65 percent increase in the average removal rates for 12–24 inches and 24–36 inches diameter at breast height (DBH) trees under its current contracts effective January 1, 2024.[1243] TURN asserts that since five percent of trees are slated for removal, the 65 percent increase in removal costs only applies to a small portion of the total costs.[1244] Although only five percent of trees are slated for removal, the price of removals is significantly higher than trims, which can result in a greater overall cost impact. With that said, SCE fails to provide any evidence demonstrating the degree to which the reported 65 percent increase for certain types of removals impacts the blended removal unit cost or the total costs for Routine Line Clearing work. Absent this information, we find it reasonable to apply a 7.5 percent escalation factor in 2024, which reflects the observed 7.1 percent increase in trim rates over 2023 along with a modest increase to reflect the observed increase in removal costs.

[1240] TURN OB at 164.

[1241] Ex. SCE-13, Vol. 10 Appendix A at A48.

[1242] SCE initially reported a 4.4 percent increase in the average standard maintenance trim rate following completed 2023 contract negotiations. However, following a vendor replacement, SCE subsequently reported a 7.1 percent increase in the 2023 rates as of May 1, 2024. (Ex. SCE-13, Vol. 10 at 36; Ex. TURN-602 at 1; RT, Vol. 13 at 1375:3-24).

[1243] Measurement of a tree trunk's diameter is referred to as Diameter at Breast Height, and is taken at a standard height off the ground. (Ex. SCE-13, Vol. 10 at 36-37 and 40).

[1244] TURN RB at 164.

Concerning TURN's proposed two percent escalation rate, we agree with SCE that the Federal Reserve Inflation Target is more of an aspirational policy metric, and find actual, observed vegetation rate increases in SCE's territory provide a more accurate forecast basis.

Lastly, SCE's Routine Line Management forecast includes $1.160 million in normalized savings attributed to the TUG capital program.[1245] As discussed in Section 16 (Wildfire Mitigation), this decision approves approximately 31 percent of the miles SCE targets for undergrounding. Accordingly, SCE's Routine Line Management forecast is adjusted to reflect 31 percent of the anticipated savings from SCE's TUG program, or $0.360 million in normalized savings.

As indicated above, the authorized TY O&M amount for Routine Line Clearing utilizes SCE's forecast methodology, with certain adjustments to the 2024 escalation rate and projected TUG savings. SCE's blended unit cost forecast for expanded line clearing is based on recent contracts and is reasonable. Further, since SCE will be charged the same rate for both maintenance and deeper trims, SCE will incur the same costs regardless of whether a contractor achieves clearance distances of six feet or 12 feet, or whether SCE's expanded line clearing forecast is approved. In contrast, TURN's alternative forecast relies on outdated forecasting assumptions from SCE's 2021 GRC and results in a TY forecast for Routine Line Clearing that is lower than what SCE recorded in 2019, prior to the increased direct and indirect costs resulting from SB 247 (Stats. 2019, ch. 406).[1246]

[1245] Ex. SCE-02, Vol. 10A at 46.

[1246] SCE RB at 56.