STATE OF CALIFORNIA GAVIN NEWSOM

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 22-05-014, *et al.*:

This is the proposed decision of Administrative Law Judge Shannon O'Rourke. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 1, 2022 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties to the proceeding may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure (Rules). Pursuant to Rule 14.6(b), all parties stipulated to reduce the 30-day public review and comment period required by Public Utilities Code Section 311 to 11 days for opening comments and seven days for reply comments.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4).

/s/ MICHELLE COOKE
Michelle Cooke
Acting Chief Administrative Law Judge

MLC:nd3
Attachment

Decision **PROPOSED DECISION OF ALJ O'ROURKE** **(Mailed 11/10/2022)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) For Approval of Its 2023 ERRA Forecast Proceeding Revenue Requirement.	Application 22-05-014
And Related Matter.	Application 22-09-017

DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S 2023 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED FORECAST REVENUE REQUIREMENT AND 2022 TRIGGER MECHANISM BALANCE

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DECISION APPROVING SOUTHERN CALIFORNIA EDISON COMPANY'S 2023 ENERGY RESOURCE RECOVERY ACCOUNT-RELATED FORECAST REVENUE REQUIREMENT AND 2022 TRIGGER MECHANISM BALANCE

Summary

This decision approves Southern California Edison Company's (SCE) total 2023 Energy Resource Recovery Account (ERRA) electric procurement cost revenue requirement forecast of $5,242.224 million,[1] modifying SCE's requested revenue requirement of $5,237.858 million to account for a correction to the Solar on Multifamily Affordable Housing Program funding true-up.

SCE's revenue requirement consists of both a generation service component and a delivery service component. As a result of the costs and other adjustments approved in this decision, on January 1, 2023, SCE's system average rates for bundled customers will increase by 2.9% as compared to rates effective October 1, 2022, to 24.444¢/kilowatt hour in 2023. The Power Charge Indifference Adjustment rates will be negative for most customer vintages in 2023 due to overcollections in 2022, resulting in credits for customers in those vintages.

Within SCE's generation service revenue requirement of $5,671.042 million, SCE is authorized to recover a total of $4,995.620 million in fuel and purchased power costs and transfer the following account balances: $835.092 million from the ERRA Balancing Account (BA), -$158.105 million from the Portfolio Allocation Balancing Account, and -$1.560 million from the Energy Settlement Memorandum Account.

Within SCE's delivery service revenue requirement of -$428.820 million, SCE is authorized to recover the following: (1) $282.419 million for the New

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[1] Includes Franchise Fees and Uncollectibles.

System Generation and System Reliability fuel and purchase power contracts; (2) $4.740 million in spent nuclear fuel costs; (3) -$11.473 million for forecast Base Revenue Requirement Balancing Account — Distribution fuel and purchased power costs; (4) -$773.198 million customer return of greenhouse gas (GHG) allowance proceeds; and (5) $14.100 million for the Public Purpose Program Charge, which includes the Tree-Mortality Non-Bypassable Charge, SCE's Preferred Resources Pilot #2, Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge, and a portion of the Disadvantaged Communities — Green Tariff and Community Solar Green Tariff program funding which provides volumetric subsidies to qualifying customer classes. SCE is also authorized to transfer the following account balances: (1) $97.951 million in the 2022 year-end balance in the New System Generation BA; (2) -$38.634 million in the 2022 year-end balance for the Tree Mortality Non-Bypassable Charge BA; and (3) -$4.725 million in the 2022 year-end BioMAT Non-Bypassable Charge BA.

This decision approves SCE's forecast GHG costs, including $452.317 million in GHG cap-and-trade costs. This decision also approves SCE's forecast of $773.198 million net GHG allowance revenues available for customer return and directs SCE to distribute $40.416 million to Emissions-Intensive and Trade-Exposed customers and $732.782 million to residential and small business customers through the California Climate Credit. The semi-annual California Climate Credit for residential and small business customers of $71 per eligible account is approved.

This decision also adopts Cost Responsibility Surcharge rates and approves SCE's ERRA Trigger Mechanism application.

SCE's procurement-related revenue requirement will be updated to reflect 2022 year-end balances with recorded actuals through December 2022. SCE will implement the rate changes on January 1, 2023, pending approval of the Tier 1 Advice Letter filed in conformance with this decision.

Consolidated applications (A.) 22-05-014 and A.22-09-017 are closed.

1. Factual Background

The factual background for Application (A.) 22-05-014 is discussed in Section 1.1. The factual background for A.22-09-017 is discussed in Section 1.2.

1.1. 2023 Energy Resource Recovery Account (ERRA) Forecast Application

In Decision (D.) 02-10-062, the Commission established the Energy Resource Recovery Account (ERRA), the power procurement balancing account required by Public Utilities (Pub. Util.) Code Section 454.5(d)(3). Pursuant to D.02-10-062 and D.02-12-074, the purpose of the ERRA is to provide recovery of energy procurement costs, including expenses associated with fuel and purchased power (F&PP), utility retained generation, California Independent System Operator (CAISO) related costs, and costs associated with the residual net short procurement requirements to Southern California Edison Company's (SCE) bundled electric service customers.

The ERRA regulatory process includes: (1) an annual forecast proceeding to adopt a forecast of the utility's electric procurement cost revenue requirement and electricity sales for the upcoming year; (2) an annual compliance proceeding to review the utility's compliance in the preceding year regarding energy resource contract administration, least cost dispatch, prudent maintenance of Utility Owned Generation (UOG) and the ERRA Balancing Account (BA); and (3) the quarterly compliance report where Energy Division reviews procurement transactions "to ensure the prices, types of products, and quantities of each product conform to the approved plan."[2]

The Commission adopted the Cost Responsibility Surcharge in D.02-11-022 (as modified by D.03-07-030), which consisted of the Competition Transition Charge (CTC). The CTC is used to recover the above-market costs of resources procured prior to market restructuring after the 2000-01 Energy Crisis.

In D.06-07-030 (as modified by D.07-01-030 and subsequently refined in D.11-12-018, D.14-10-045, D.18-10-019, D.19-10-001, D.20-01-030, D.20-03-019, D.20-08-004, and D.21-05-030), the Commission adopted the Power Charge Indifference Adjustment (PCIA) for determining the above-market costs associated with the utility/California Department of Water Resources (CDWR) Power Charge as an element of the Cost Responsibility Surcharge. The PCIA applies to departing load customers who are responsible for a share of the CDWR power contracts or new generation resource commitments. The PCIA is intended to ensure that departing load customers pay their share of the above-market portion of the CDWR contract and generation resource costs incurred on their behalf, and that bundled customers remain indifferent to customer departures.

The electric utilities are also required to incorporate greenhouse gas (GHG) costs into the generation component of electricity rates through the ERRA process.[3] Incorporating the costs of GHG emissions into rates results in a carbon price signal intended to incent an overall decrease in energy consumption and reduction in GHG emissions.[4] Finally, the electric utilities are required to report

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[2] D.02-10-062 at 47, 50.

[3] D.12-12-033; D.14-10-033.

[4] D.14-10-033.

and return annual GHG allowance revenues to eligible customers. Pursuant to Pub. Util. Code Section 748.5(c), the Commission can allocate up to 15% of GHG allowance revenues for clean energy and energy efficiency projects which are approved by the Commission, but not funded by another source.

1.2. 2022 ERRA Trigger Mechanism Application

Pursuant to Assembly Bill (AB) 57 (Stats. 2002, Ch. 835), the Commission established the ERRA BA in 2002 to record the investor-owned utilities' (IOU) F&PP revenues against actual recorded costs, excluding revenues collected for the CDWR.[5] AB 57 also mandated a rate adjustment to promptly amortize any overcollection or undercollection to ensure that an electric utility's power procurement balancing accounts do not exceed the AB 57 threshold amount of five percent of the electrical utility's actual recorded generation revenues for the prior calendar year, effective until January 1, 2006, and as deemed appropriate by the Commission consistent with the objectives of Pub. Util. Code Section 454.5(d)(3) thereafter.[6]

D.02-10-062, which implemented AB 57, requires an electrical utility to file an expedited application when its ERRA BA balance exceeds four percent of the prior year's recorded revenue requirement (trigger point) and is expected to exceed five percent of the prior year's recorded revenue requirement (AB 57 threshold amount) in order to promote the timely recovery of an IOU's procurement costs for undercollections or facilitate reimbursement to ratepayers for overcollections (ERRA trigger mechanism).[7]

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[5] Pub. Util. Code § 454.5(d)(3), enacted by AB 57.

[6] *Ibid.*

[7] D.02-10-062 at 64-66.

In D.06-06-051, the Commission modified SCE's ERRA trigger mechanism to allow SCE to file an Advice Letter when its ERRA BA balance exceeded the four percent trigger point, if SCE did not propose to change rates and if it expected the ERRA BA balance exceedance to go below the trigger point within 120 days.[8] SCE was still required to file an expedited application when its ERRA BA balance exceeded the trigger point and rate changes were necessary to amortize the balance.[9] SCE was required to monitor its ERRA BA balance on a frequent basis and timely file expedited ERRA trigger applications.[10] In D.19-12-001, the Commission clarified that SCE should file an expedited trigger application if SCE could not reasonably determine that the ERRA BA balance would self-correct within 120 days.

Prior to the Commission's modification of its PCIA methodology in D.18-10-019, SCE recorded the majority of its procurement revenue requirement in the ERRA BA and calculated the PCIA as an estimated value using market price benchmarks.[11] In D.18-10-019, the Commission adopted a methodology to true-up above-market power procurement costs and established the Portfolio Allocation Balancing Account (PABA) to record above market procurement costs for bundled and departed load customers by vintage.[12] Effective January 1, 2020, SCE started recording the costs of short-term market purchases for bundled service customers in the ERRA BA, while recording long-term fixed-price

[8] D.06-06-051 at 10 (Ordering Paragraph (OP) 3).

[9] *Ibid.* (OP 5).

[10] *Id. at* 9 (OP 2).

[11] Procurement costs of Green Tariff Shared Renewables (GTSR) were recorded in the GTSR BA for bundled customers. Procurement costs for New System Generation (NSG) resources were recorded in the NSG BA.

[12] D.18-10-019 OP 7.

contract costs and utility-owned generation costs for bundled and departed load customers in the PABA.[13] As a result, SCE evaluates its trigger point and AB 57 threshold amount using both the ERRA BA balance and the bundled customer portion of its procurement-related revenue balance recorded in the PABA.

2. Procedural Background

The procedural backgrounds for A.22-05-014 and A.22-09-017 are discussed in Section 2.1 and Section 2.2, respectively.

2.1. 2023 ERRA Forecast Application

On May 16, 2022, SCE filed A.22-05-014 requesting Commission approval of the 2023 ERRA forecast revenue requirement (Application). On June 17, 2022, The Utility Reform Network filed a timely protest to the Application. On June 20, 2022, Clean Power Alliance of Southern California (CPA), California Choice Energy Authority (CalChoice), and Central Coast Community Energy (CCCE) (collectively, SoCal CCAs), jointly, Coalition of California Utility Employees (CUE), Direct Access Customer Coalition (DACC), and the Public Advocates Office of the California Public Utilities Commission (Cal Advocates) filed timely protests to the Application. On June 30, 2022, SCE filed a reply to parties' protests.

A prehearing conference (PHC) was held on July 26, 2022, to discuss the issues of law and fact and determine the need for hearing and schedule for resolving the matter. The assigned Commissioner issued a Scoping Memo and Ruling on August 12, 2022.

SCE held a workshop to discuss its application on August 23, 2022. On August 29, 2022, SoCal CCAs served intervenor testimony. On

[13] *See* SCE AL 3914-E; Exhibit SCE-01 at 15.

September 14, 2022, SCE served rebuttal testimony. On September 21, 2022, SCE filed a joint case management statement indicating no evidentiary hearings were needed. On September 21, 2022, evidentiary hearings were taken off-calendar by ruling. California Community Choice Association's August 23, 2022 motion for party status was granted on September 21, 2022.

SCE served its October Update testimony on October 10, 2022. The assigned Commissioner issued a scoping memo on October 21, 2022, consolidating A.22-05-014 with A.22-09-017. On October 26, 2022, SCE and SoCal CCAs filed opening briefs. On November 2, 2022, SCE filed a reply brief.

The Commission has jurisdiction to review an IOU ERRA forecast application pursuant to Pub. Util. Code Section 454.5(d)(3).

2.2. 2022 ERRA Trigger Mechanism Application

On September 30, 2022, SCE filed A.22-09-017, requesting approval of its Expedited ERRA trigger mechanism application (ERRA Trigger Application), which addressed an undercollection in the ERRA Balancing Account that: (1) exceeded the four percent ERRA trigger point and was expected to exceed the five percent ERRA threshold pursuant to AB 57; and (2) was not expected to self-correct within 120 days.

On October 4, 2022, a PHC was set by Acting Chief Administrative Law Judge (ALJ) ruling and served concurrently on the service list for A.22-05-14 and A.22-09-017. The ruling also shortened the protest and reply period, and stated the Commission's intent to discuss consolidation of A.22-09-017 with A.22-05-014 at the PHC. On October 11, 2022, SoCal CCAs filed a response to the ERRA Trigger Application.

A remote PHC was held on October 19, 2022, to discuss the issues of law and fact, to determine the need for hearing and schedule for resolving the matter, and consolidation of A.22-05-014 with A.22-09-017. The assigned Commissioner issued a scoping memo on October 21, 2022, consolidating A.22-05-014 with A.22-09-017.

The Commission has jurisdiction to review an IOU ERRA trigger application pursuant to Pub. Util. Code Section 454.5(d)(3).

3. Issues Before the Commission

The issues to be determined or otherwise considered are:

1. Whether SCE's requested 2023 ERRA forecast revenue requirement is reasonable, including but not limited to consideration of the following:
    a. SCE's forecast of electric sales and electric load;
    b. SCE's forecast costs for fuel and purchased power expenses;
    c. SCE's forecast costs for spent nuclear fuel interim storage;
    d. SCE's forecast Greenhouse Gas (GHG) costs; and
    e. Annual true-ups for balancing accounts such as the Portfolio Allocation Balancing Account (BA), New System Generation BA; Energy Settlements Memorandum Account, ERRA BA, BioMAT Non-Bypassable Charge, and Tree Mortality Non-Bypassable Charge BA.
2. Whether SCE's forecast of GHG allowance revenue return allocations for energy-intensive trade-exposed customers, small business customers, and the residential customer California Climate Credit is reasonable;
3. Whether SCE's forecast of GHG revenues and expenses set aside for (1) clean energy and energy efficiency programs and GHG administration; and (2) customer education and outreach plan costs is reasonable;
4. Whether SCE's forecast of Central Procurement Entity-related costs is reasonable;

5. Whether the Cost Allocation Mechanism rates are reasonable;
6. Whether SCE's calculations of the PCIA and CTC are reasonable, including discussion of the following:
    a. Treatment of Resource Adequacy resources and associated costs in the PCIA;
    b. Treatment of Renewable Portfolio Standard (RPS) resources with excess RPS value and allocation of RPS sales across vintages;
    c. Calculation of the indifference amount;
    d. Calculation of the year-end Portfolio Allocation BA balance; and
    e. Allocation of indifference charges among vintages and customer classes.
7. Whether and to what extent the Voluntary Allocation and Market Offer framework adopted by the Commission in D.21-05-030 impacts the issues described above;
8. Whether SCE's requests and methods used to determine the issues described above comply with all applicable rules, regulations, resolutions, and decisions for all customer categories; and
9. Whether there are any safety concerns.

The issues to be determined in the ERRA Trigger Application are:

1. Whether SCE complied with the law and Commission orders, including D.02-10-062, D.04-12-048, D.06-06-051, D.19-12-001, and D.22-08-023 in addressing the Undercollection;
2. Whether the ERRA trigger point-related balance exceeded the trigger point, and whether it was likely that the balance would self-correct within 120 days of the trigger point balance exceedance;
3. The causes of the Undercollection (excluding reasonableness review or compliance with SCE's bundled procurement plan);

4. The appropriate amortization period of the ERRA Balancing Account balance, if any;
5. The impact on rates of the Undercollection recovery; and
6. Whether the proposed allocation of the Undercollection among customers for the rate adjustment is reasonable.

4. 2023 Forecast Overview and Methodology

SCE's forecast F&PP costs are associated with its UOG resources, purchased power contracts, financing, various carrying costs, and procurement contracts to meet reliability requirements set by the Commission. SCE forecasts its 2023 total F&PP revenue requirement at $5,285.403 million.[14]

SCE bases its revenue requirement on a forecast of total electricity sales and customers for its service territory that was completed in December 2021, which it adjusts to account for the bundled customer portion of load. SCE's total retail electricity sales volume in 2021 was 85,600 gigawatt hours (GWh).[15] SCE's forecast of total electricity sales in 2023 is 85,327 GWh, which is slightly higher than its forecast electricity sales of 85,156 GWh in 2022.[16] This represents a total reduction in annual total retail sales of 0.5% in 2022 and 0.3% in 2023 compared to 2021.[17] At the same time, SCE forecasts an increase of 0.6% in total electricity customers in its service territory from 5,200,618 in 2022 to 5,230,870 in 2023.[18] SCE's retail sales forecast is influenced by historical trends in employment growth, residential housing starts, the economic outlook, weather assumptions

[14] Exhibit SCE-05C at 7.

[15] *Id.* at 12.

[16] *Ibid.*

[17] *Id.* at 13-14.

[18] *Id.* at 15.

and other factors (*e.g.*, energy efficiency savings, spending on wildfire mitigation, grid safety and resiliency).

SCE calculates the revenue requirement necessary for procuring bundled customer energy in 2023 using energy need at the CAISO interface, which allows SCE to account for line losses inherent in transporting energy from the CAISO interface to bundled service customers' meters.[19] SCE also adjusts the sales forecast downward 3.11% to adjust for the difference between billed and delivered energy for its bundled service Net Energy Metering (NEM) customers.[20]

Finally, SCE's 2023 forecast of total bundled service customers accounts for the statewide increase in the DA load cap, which started in 2021.[21] It also includes Energy Service Providers and Community Choice Aggregators (CCA)[22] that meet one of the following criteria: (1) file a binding notice of intent to begin community choice aggregation service; (2) file an initial RA filing; (3) start community choice aggregation service; or (4) formally submit an April RA forecast pursuant to Pub. Util. Code Section 380.

5. SCE's Portfolio of Resources

SCE's portfolio of resources includes a variety of utility owned and contracted resources as discussed in Section 5.1 through Section 5.13 below.

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[19] *Id*. at 12.

[20] *Id*. at 13.

[21] *Id*. at 15.

[22] SCE included the following CCAs in its 2023 ERRA forecast: (1) Lancaster Choice Energy; (2) Apple Valley Choice Energy; (3) Pico Rivera Innovative Municipal Energy; (4) CPA (Phases 1-5); (5) San Jacinto Power; (6) Rancho Mirage Energy Authority; (7) CCCE; (8) Pomona; (9) Baldwin Park; (10) Palmdale Phase I; (11) City of Santa Barbara; and (12) Orange County Power Authority Phase 1 and Phase 2.

5.1. UOG and Purchased Power Contracts — Hydroelectric, Combined Heat and Power (CHP), Solar Photovoltaic Program, Renewables, and Natural Gas

SCE's UOG and purchased power contract resources consist of hydroelectric, fuel cells, CHP and renewable generation resources, nuclear, natural gas and battery storage. SCE's hydroelectric resources consist of 33 powerhouses with a 1,176 megawatt (MW) nameplate capacity, which are organized into the Northern[23] and Eastern[24] Divisions.[25] SCE forecasts a slightly-below-normal hydrological year for 2023 and incorporates planned outages for hydroelectric units.[26]

SCE's solar photovoltaic resources consist of the Solar Photovoltaic Program, which allows SCE to install, own, and operate up to 91 MW of direct current solar photovoltaic projects in SCE's service territory.[27]

SCE's CHP and renewable resources consist of approximately 10,205 MW of contract capacity, which include 401 MW of CHP capacity and 9,803 MW of renewable capacity.[28] In addition, SCE expects one approximately 3 MW solar project to begin delivering from June 2022 through December 2023.[29] SCE's CHP and renewables projects include biomass, cogeneration, geothermal, small

[23] The Northern Division, known as the Big Creek Project, is in central California in the western Sierra Nevada Mountains.

[24] The Eastern Division consists of 24 powerhouses in the eastern and southern Sierra Nevada Mountain, the San Bernardino Mountains and San Gabriel Mountains.

[25] Exhibit SCE-01C at 32.

[26] *Id*. at 33.

[27] *Ibid*.

[28] *Id*. at 34.

[29] *Ibid*.

hydroelectric, solar and wind resources.[30] SCE estimates curtailments of certain solar and wind projects in 2022 for economic reasons.[31]

SCE's natural gas resources consist of five black-start capable peakers with a total capacity of 245 MW.[32] Natural gas costs incurred by the five peakers are included in the ERRA forecast, while the capacity and non-fuel variable costs associated with these peakers are included in SCE's General Rate Case (GRC) revenue requirement.[33]

5.2. Interagency Contracts

SCE is a party to two inter-utility contracts with dispatchability, which affects forecast F&PP costs. For 2023, SCE has an entitlement of 280.245 MW of contingent capacity and 238.16 GWh of firm energy through a contract with the Western Area Power Administration (WAPA) and the Bureau of Reclamation from power generated by the Hoover Dam.[34] However, SCE forecasts the monthly capacity and firm energy available to it in 2023 could be as low as 115 MW and 10 GWh, respectively, due to the decreased surface elevation of Lake Mead, the forebay of the Hoover Dam.[35]

SCE also purchases power from the City of Pasadena from the 3 MW Azusa Powerhouse, which SCE transferred to the City of Pasadena through a Corporation Grant Deed. The Corporation Grant Deed requires the City of Pasadena to deliver the entire electrical output of the Azusa Powerhouse

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[30] *Id*. at 35.

[31] *Id*. at 39.

[32] *Ibid*.

[33] *Ibid*.

[34] *Id*. at 40.

[35] *Id*. at 40-41.

to SCE, and the City of Pasadena has 12 months from the time of delivery to request the same amount of energy.[36]

5.3. Resource Adequacy (RA) Contracts

In D.06-07-029, as modified by D.10-12-035 and Senate Bill 695, the Commission adopted a cost allocation mechanism (CAM) to allocate the costs electric utilities incur to meet RA requirements on behalf of customers in an electric utility's service territory. In D.10-12-035, the Commission also allowed SCE to allocate costs associated with CHP generation procured on behalf of Direct Access customers' Electric Service Providers and CCAs.

SCE forecasts 2023 F&PP costs associated with six types of RA generation resources: (1) New System Generation CAM contracts; (2) System Reliability Modified CAM contracts; (3) Emergency Reliability contracts; (4) Mid-Term Reliability contracts; (5) Generic and Bilateral contracts used to meet 2023 system capacity requirements; and (6) Contracts used to meet local capacity requirements.

First, SCE forecasts costs from New System Generation CAM contracts procured pursuant to D.07-09-044, for which it plans to hold the dispatch rights in 2023.[37] SCE does not use the energy from these contracts to meet bundled load, and the net capacity costs[38] are allocated to benefitting customers through the CAM.

Second, SCE forecasts costs associated with resources procured in accordance with D.19-11-016's order directing SCE to procure 1,184.7 MW of

[36] *Id*. at 42.

[37] *Id*. at 43.

[38] The net capacity costs are the net of estimated expected revenue and production costs.

incremental system RA capacity.[39] In April 2020, SCE executed seven "Fast Track" contracts for new energy storage resources, which were approved in Resolution E-5101.[40] SCE executed an additional five "Standard Track" contracts for various energy projects, which were approved in Resolution E-5142.[41]

Third, the Commission also authorized the IOUs to procure resources for emergency system reliability requirements. In D.21-02-028, the Commission authorized the IOUs to contract for capacity that is available to serve peak and net peak demand in the summer of 2021, and seek approval for recovery of rates through CAM. In D.21-03-056, the Commission authorized the IOUs to procure resources to meet the summer 2021 and 2022 effective planning reserve margin. In D.21-12-015, the Commission adopted requirements for summers 2022 and 2023.

Fourth, the Commission required load serving entities within the CAISO's operating system to procure at least 11,500 MW of net qualifying capacity by 2025 to address mid-term reliability needs. SCE's share of the procurement responsibility is 4,052 MW by 2026.[42] SCE executed contracts for five energy storage projects, which were approved in Resolution E-5205.

Fifth, SCE forecasts RA purchase costs for generic RA using the RA market price benchmark and the revenue from sale of excess RA.[43]

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[39] Exhibit SCE-05C at 37.

[40] *Id.* at 38.

[41] *Ibid.*

[42] Exhibit SCE-01C at 45-46.

[43] *Id.* at 47.

Finally, SCE forecasts costs for RA resources procured through Local Capacity Requirement solicitations in the Western Los Angeles[44] and Moorpark[45] subareas.[46] Starting in 2023, SCE will begin procurement for RA resources as Central Procurement Entity (CPE) for its distribution service area.[47]

5.4. Public Purpose Program Charge

SCE will incur procurement-related expenses for three programs recovered through the Public Purpose Program charge. First, SCE will incur costs related to electrical energy, capacity, and renewable attributes contracted through its PRP #2.[48] SCE incorporates forecast, monthly in-front-of the meter energy costs[49] from the PRP #2 into the F&PP forecast.

Second, SCE incurs above-market costs associated with biomass contracts procured pursuant to D.18-12-003. The Tree Mortality Non-Bypassable Charge BA records the net costs of tree mortality-related biomass energy procurement mandated by Pub. Util. Code Section 399.20.3(f).[50] The net costs include the costs of procurement, but exclude the value received from the IOUs for: (1) energy or ancillary services sales; (2) the value of renewable energy credits (RECs) associated with the biomass contracts; and (3) the RA capacity value of the

[44] D.15-11-041.

[45] D.16-05-050; D.19-12-055.

[46] Exhibit SCE-01C at 47.

[47] D.20-06-002.

[48] Exhibit SCE-01C at 47-48.

[49] Behind-the-meter Local Capacity Requirement resources from the PRP reduce the overall bundled load requirement and are not included in the F&PP forecast.

[50] D.18-12-003 at 2.

contracts.[51] The net costs also include costs associated with audits of the BioRAM program.[52]

Third, SCE's net costs associated with the BioMAT program are recovered through the BioMAT Non-Bypassable Charge, which is part of the Public Purpose Program Charge.[53] The BioMAT program established a feed-in tariff for bioenergy and required the IOUs to procure an additional 250 MW of renewable feed-in tariff resources from small scale bioenergy projects that commence operations after June 1, 2013.[54] SCE forecasts a net revenue requirement of $7.512 million for F&PP costs associated with the BioMAT Non-Bypassable Charge in 2023.[55]

Finally, SCE recovers the portion of the costs for the Disadvantaged Communities — Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT) programs, which are not otherwise recoverable through GHG allowance revenue, through the Public Purpose Program charge, as discussed in Section 7.4.2.

5.5. Green Tariff Shared Renewables Program

In 2015, the Commission established the Green Tariff Shared Renewables program pursuant to Pub. Util. Code Sections 2831-2833.[56] The Green Tariff Shared Renewables program provides customers with two options for obtaining a greater mix of renewable energy. Under the Green Tariff option, marketed as

[51] *Id*. at 2, 25 (OP 1).

[52] Resolutions E-4805 and E-4770; Exhibit SCE-01C at 116-117.

[53] Prior to D.20-08-043, the BioMAT program costs were recorded in vintages subaccounts of the PABA and recovered through the PCIA surcharge.

[54] Senate Bill 1122 (Rubio, 2012); D.20-08-043.

[55] Exhibit SCE-05C at 113.

[56] D.15-01-051.

the Green Rate program at SCE, customers may choose either a 50% or 100% option for the mix of renewable energy with a corresponding increase in their generation rate. Under the Enhanced Community Renewables option, customers may support local renewable energy projects through agreements with third-party developers.

SCE forecasts 165,427,386 kilowatt hours (kWh) of participation through the Green Tariff Shared Renewables program in 2023.[57] The forecast kWh to serve Green Tariff Shared Renewables customers is removed from the CHP and Renewables energy and shown separately, as the resources to generate the energy are now online and expected to produce power in 2023.[58]

5.6. Nuclear

SCE has ownership interests in the San Onofre Nuclear Generating Station (SONGS), a nuclear power facility which ceased operations in 2013, and the Palo Verde Nuclear Generating Station (PVNGS), a nuclear power facility operated by the Arizona Public Service.[59] SCE forecasts $4.7 million in costs for interim spent fuel storage costs at SONGS in 2023.[60] SCE forecasts $29.8 million in nuclear fuel expenses and $0.0 million in net interim used fuel storage charges at PVNGS, due to a credit of $1.7 million from a damages award payment from the United States Department of Energy from litigation to recover spent fuel storage costs.[61]

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[57] Exhibit SCE-05C at 43.

[58] Exhibit SCE-01C at 48-49.

[59] *Id*. at 49.

[60] Exhibit SCE-05C at 47.

[61] *Id.* at 44-47.

5.7. Catalina Fuel Costs

SCE forecasts a total fuel cost of $9.482 million to provide electricity service to Santa Catalina Island using six diesel generators and 23 propane-fired micro-turbines at the Pebbly Beach Generating Station.[62] This fuel cost forecast includes $8.976 million for diesel fuel based on a forecast use of 49,439 barrels of diesel at an average commodity cost of $181.71 per barrel.[63] It also includes a forecast of $0.505 million in propane costs to operate the microturbines in 2023.[64]

5.8. Demand Response

SCE forecasts an estimated 6 GWh of energy reductions in 2023 provided by economic demand response programs, including the Summer Discount Plan, Capacity Bidding Program, Critical Peak Pricing, and Smart Energy Program.[65] SCE does not include the costs associated with demand response programs that provide reliability, which are programs that require participants to reduce their load in response to a forecast or actual system emergency.[66] SCE records the cost of all demand response incentives in the Demand Response Program Balancing Account (DRPBA) pursuant to D.17-12-003.[67] Year-end balances in the Incentives subaccount are transferred to the Base Revenue Requirement BA.[68]

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[62] *Id.* at 51.

[63] *Id.* at 49

[64] *Ibid.*

[65] Exhibit SCE-01C at 57.

[66] *Ibid.*

[67] *Id.* at 58.

[68] Exhibit SCE-05C at 52.

5.9. CAISO Costs, Load Procurement and PABA Energy Revenue

The forecast CAISO cost is the net cost of the following: grid management charges, Federal Energy Regulatory Commission fees, Congestion Revenue Rights auction-related costs, ancillary services, CAISO uplift costs, Standard Capacity Product costs, and other non-energy-related CAISO costs.[69] The forecast load procurement charge is the cost of procuring load, estimated by multiplying the hourly load by the south of path 15 zone of the CAISO control area (SP15) price for the corresponding hour.[70] SCE calculates the forecast energy revenues by multiplying the forecast production of its CAM and PABA-eligible resources by the corresponding hourly SP15 price.[71]

5.10. Hedging Costs

SCE's forecast hedging costs include energy-related transaction fees and option premiums for hedging SCE's open energy position in 2023.[72]

5.11. Gas Transportation and Storage

SCE forecasts $4.433 million of costs associated with natural gas delivery for 2023.[73] This includes the costs of: (1) a daily reservation charge for Backbone Transportation Service rights; and (2) a fixed monthly customer charge to deliver natural gas to SCE's UOG fuel cells at University of California at Santa Barbara and California State University at San Bernardino.[74] It also includes SCE's forecast costs associated with a month-to-month contract with Southern

[69] Exhibit SCE-01C at 53-54.

[70] *Id*. at 59.

[71] *Id*. at 60.

[72] *Id*. at 75.

[73] *Id*. at 76.

[74] *Ibid*.

California Gas Company to transport natural gas to the Mountainview Generating Station along with delivery to SCE's Barre, Center, Grapeland, McGrath and Mira Loma peakers.[75]

5.12. Financing Costs

SCE has a $3.35 billion multi-year revolving credit facility, also called the "revolver," to serve short-term borrowing requirements.[76] In 2022, SCE exercised an option to extend the revolver one additional year through 2026.[77] Forecast costs and other aspects of the revolver include: (1) $20,000 administrative fee; (2) 17.5 basis point annual facility fee; (3) 107.5 basis point participation fee on any outstanding letters of credit; (4) 20 basis point issuer fee on any letters of credit; and (5) Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points borrowing (loan) rate.[78] In 2023, SCE forecasts using funds from the revolver to provide capacity for collateral and supporting balancing accounts.[79]

SCE issued a 3-year $100 million fixed-rate bond in June 2021 to pay for fuel inventories.[80] SCE plans to issue a 3-year $100 million fixed rate bond in January 2023 to support fuel inventories, which is forecast to have an interest rate of 4.85% and incur approximately $0.550 million in issuance costs and expenses, which will record in 2023.[81] In 2023, SCE proposes to use a $3 billion commercial

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[75] *Id*. at 76-77.

[76] Exhibit SCE-05C at 71.

[77] *Ibid.*

[78] *Id*. at 72.

[79] *Ibid*.

[80] *Id*. at 73.

[81] *Ibid.*

paper program to finance fuel inventories in excess of the amount of the $100 million fixed rate bond.[82] In addition, SCE proposes to provide collateral to counterparties in the form of letters of credit rather than cash; fees associated with letters of credit will be charged to the ERRA-related balancing accounts.[83]

5.13. Carrying Costs — Fuel Inventory, GHG Compliance and Collateral

SCE forecasts fuel inventory carrying costs for nuclear, natural gas, and diesel.[84] SCE also forecasts GHG procurement compliance carrying costs for 2023, which SCE estimates using historical GHG inventory balances and the ERRA BA interest rates.[85] Finally, SCE forecasts the carrying costs associated with SCE's collateral requirements necessary to procure power.[86]

6. SCE's Revenue Requirement and Ratemaking Proposal

SCE proposes to divide its ERRA revenue requirement between generation service, which applies to bundled customers, and delivery service, which applies to both bundled and unbundled customers. SCE's generation service revenue requirement is discussed in Section 6.1 while SCE's delivery service requirement is discussed in Section 6.2.

SCE forecasts its total system average rates will increase by 2.9% to 24.444¢/kWh in 2023.[87] While SCE initially forecast a rate decrease for 2023, SCE states that its forecast revenue requirement for October 2022 was $971.719 million

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[82] *Ibid.*

[83] *Ibid.*

[84] *Id.* at 75.

[85] *Id.* at 76.

[86] *Ibid.*

[87] *Id.* at 143. (The rate increase percentage is relative to rates as of October 1, 2022.)

higher than its forecast in May 2022 due to the following factors: (1) significantly higher market prices for gas and power; and (2) inclusion of new resources procured for Emergency Reliability and Midterm Reliability that occurred after May.[88] SCE's forecast revenue requirement is $838.254 million more than the revenue requirement reflected in rates through October 2022.[89] SCE's proposed average rates by customer class are summarized in Table 6-1 below.

Table 6-1. SCE's Proposed 2023 ERRA Forecast Average Rates by Customer Class[90,91]

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	% Change from 10/1/2021
Domestic				
• D	16.964	14.534	31.499	2.9%
• D-CARE	5.237	14.536	19.733	2.0%
• D-APS	15.726	14.545	30.271	5.0%
• DE	9.353	14.528	23.880	4.3%
• DM	4.824	14.576	19.399	-41.7%
• DMS-1	17.374	14.576	31.950	-3.1%
• DMS-2	17.300	14.575	31.875	1.3%
Lighting-Small, Med. Power				
• GS-1	12.706	13.997	26.702	4.8%
• GS-2	15.329	12.544	27.873	3.1%
• TC-1	18.412	11.363	29.775	-0.5%
• TOU-GS	13.017	11.542	24.559	3.8%

88 *Id*. at 6.

89 *Ibid*.

90 Exhibit SCE-05 at 143.

91 Acronyms for customer classes are defined in Appendix A.

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	% Change from 10/1/2021
Large Power				
• TOU-S	10.792	10.722	21.514	5.2%
• TOU-P	9.606	10.271	19.876	4.5%
• TOU-T	3.576	9.501	13.076	11.8%
• TOU-8-S-S	11.442	11.437	22.879	9.1%
• TOU-8-S-P	11.501	10.847	22.348	9.0%
• TOU-8-S-T	4.634	9.784	14.419	14.4%
Agricultural & Pumping				
• TOU-PA-2	13.241	12.176	25.417	9.6%
• TOU-PA-3	9.857	9.974	19.831	3.9%
Street & Area Lighting				
• LS-1	45.286	7.766	53.052	0.4%
• LS-2	15.725	7.7759	23.484	0.9%
• LS-3	7.491	7.774	15.266	6.0%
• DTL	35.490	7.766	43.256	0.4%
• OL-1	29.430	7.766	37.196	0.5%
Average Rate — All Groups	12.020	12.424	24.444	2.9%

6.1. Generation Service Revenue Requirement

The generation service revenue requirement recovers F&PP costs, along with the associated GHG costs of resources, recorded in the following accounts: (1) ERRA BA; (2) PABA; (3) Green Tariff Shared Renewables BA; and (4) the Energy Settlement MA, as discussed in Section 6.1.1 through Section 6.1.4 and summarized in Table 6-2 below. SCE's forecast generation service requirement is $838.254 million more in 2023 than its generation service revenue requirement from rates in effect today.[92]

[92] Exhibit SCE-05C at 9.

This decision adopts a total generation revenue requirement of $5,671.042 million.

Table 6-2. Summary of SCE's Proposed and the Commission Adopted Generation Service Revenue Requirement[93]

Description	**SCE Proposed 2023 Revenue Requirement (millions)**	**Commission Adopted 2023 Revenue Requirement (millions)**
2023 F&PP Costs (including GHG costs) • ERRA BA-related • PABA-related • Green Tariff Shared Renewables BA-related	 $5,067.457 -$81.655 $9.814	 $5,067.457 -$81.655 $9.814
2022 ERRA BA True-up	$835.092	$835.092
2022 PABA True-Up	-$158.105	-$158.105
2022 Energy Settlement MA True-Up	-$1.560	-$1.560
Total Generation Service	**$5,671.042**	**$5,671.042**

6.1.1. ERRA BA

The ERRA BA records the difference between SCE's ERRA-related revenue requirement and its F&PP expenses for bundled service customers during the prior year. For 2023, SCE forecasts a total revenue requirement of $5,067 million that will record to the ERRA BA for F&PP costs for wholesale short-term market purchases and F&PP contract costs for resources not eligible for recovery through the PABA, New System Generation BA, or any other account.[94] This includes $0.500 million in F&PP-related subscription fees.[95] Subscription fees are

[93] Exhibit SCE-05 at 10.

[94] Exhibit SCE-05C at 99.

[95] *Ibid*.

used to "perform key market functions including monitoring independent market data, risk reports, power prices, natural gas prices, emissions prices, and industry news," and to calculate the Short-Run Avoided Cost price for qualifying facilities.[96]

In its October Update testimony, SCE forecasts a $835.092 million undercollection in the ERRA BA by December 31, 2022, which SCE proposes to collect from bundled service customers in 2023.[97] According to SCE, the undercollection results from higher than forecast gas and electric power prices starting in the second quarter of 2022 as well as higher than forecast customer load.[98]

Upon consideration, we find SCE's forecast ERRA BA revenue requirement and 2022 ERRA BA undercollection recovery proposal reasonable and in compliance with applicable rules, orders and Commission decisions.

6.1.2. PABA

The PABA records the costs of long-term, fixed-price contract costs and utility-owned generation costs for bundled and departed load customers (*see* Section 5 above for specific resource types). SCE forecasts negative $81.655 million in F&PP costs in the PABA for bundled service customers in 2023 through the generation service component of its revenue requirement.[99]

SCE also forecasts an overcollection of $158.105 million in its 2022 PABA balance by December 31, 2022.[100] SCE states the forecast overcollection is a result

[96] *Id*. at 69.

[97] *Id*. at 98.

[98] *Id*. at 101.

[99] *Id*. at 99.

[100] *Id*. at 102.

of the true-up of the forecast and final RA adders and is highly dependent on forecast overcollections materializing from September through December 2022 based on forecasts of forward power prices.[101]

Upon consideration, we find SCE's forecast 2023 PABA and 2022 PABA year-end true-up reasonable and in compliance with applicable rules, orders, and Commission decisions.

6.1.3. Green Tariff Shared Renewables BA

The Green Tariff Shared Renewables BA records the difference between the costs and revenues collected for Green Tariff Shared Renewables-commodity resources, used for both the Green Tariff option[102] and the Enhanced Community Renewables option[103] of the Green Tariff Shared Renewables program.

SCE forecasts Green Tariff participation at 165,427,386 kWh in 2023[104] and forecasts a revenue requirement of $9.814 million for F&PP costs related to three Green Tariff Shared Renewables program resources.[105]

The Commission finds SCE's proposed 2023 Green Tariff Shared Renewable BA amount accurate, reasonable, and in compliance with applicable rules, orders and Commission decisions.

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[101] *Ibid*.

[102] Under the Green Tariff option, customers can choose to allocate either 50% or 100% of their electricity bill to renewable energy.

[103] Under the Enhanced Community Renewables option, customers can support local renewables projects through agreements with third-party energy developers.

[104] Exhibit SCE-05C at 43.

[105] *Id*. at 100.

6.1.4. Energy Settlement MA and Litigation Costs Tracking Account (TA) Subaccount

The Energy Settlement MA tracks refunds from generators who overcharged SCE for electricity during the 2000-2001 California Energy Crisis. The Litigation Costs TA is a subaccount in the Energy Settlement MA, which tracks litigation costs "set-aside" in Federal Energy Regulatory Commission investigation settlement agreements and actual litigation costs incurred by SCE.

SCE estimates a December 31, 2022 credit of $1.865 million including franchise fees and uncollectibles (FF&U) related to refunds from generators who overcharged SCE for electricity during the 2000-2001 California Energy Crisis.[106] SCE estimates a December 31, 2022 balance of $0.304 million including FF&U in litigation costs in the Litigation Costs TA.[107] In total, SCE has an overcollection of $1.560 million in the Energy Settlement MA and Litigation Costs TA.[108]

The Commission finds SCE's proposed amounts in the Energy Settlement MA and Litigation Costs TA accurate, reasonable and in compliance with applicable rules, orders and Commission decisions.

6.2. Delivery Service Revenue Requirement

SCE forecasts a total delivery service revenue requirement of negative $433.184 million in 2023. The delivery service revenue requirement is recovered from all bundled and departing load SCE customers through allocation mechanisms other than the CTC, PCIA, and the Wildfire Non-Bypassable Charge.

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[106] *Id.* at 102.

[107] *Id.* at 103.

[108] *Ibid.*

Due to a correction to the GHG Allowance Revenue forecast (discussed in Section 6.2.4), we adjust the delivery service revenue requirement and adopt a delivery service requirement of negative $428.820 million.

The delivery service revenue requirement forecast includes F&PP and GHG costs of resources associated with the following: (1) 2023 New System Generation forecast costs (including CPE-related costs) and true up costs (*see* Section 6.2.1); (2) Spent Nuclear Fuel Costs (*see* Section 6.2.2); (3) the distribution sub-account of the Base Revenue Requirement BA (*see* Section 6.2.3); (4) GHG Allowance revenue return (*see* Section 6.2.4); and (5) the Public Purpose Program Charge (*see* Section 6.2.5).

Table 6-3. Summary of SCE's Proposed and Commission Adopted Delivery Service Revenue Requirement[109]

Description	SCE Proposed 2023 Revenue Requirement (millions)	Commission Adopted 2023 Revenue Requirement (millions)
New System Generation		
• New System Generation F&PP 2023 Forecast[110] and 2023 System Reliability F&PP	$282.419	$282.419
• New System Generation BA 2022 True-Up	$97.951	$97.951
Spent Nuclear Fuel	$4.740	$4.740
Distribution Rate Component		
• Base Revenue Requirement BA-Distribution F&PP 2023 Forecast	-$11.473	-$11.473
• GHG Allowance Revenues 2023 Forecast	-$777.564	-$773.198

[109] Exhibit SCE-05 at 94.

[110] Estimate includes indirect GHG costs.

Description	SCE Proposed 2023 Revenue Requirement (millions)	Commission Adopted 2023 Revenue Requirement (millions)
Public Purpose Programs Charge		
• Public Purpose Program F&PP Charge 2023 Forecast	$14.100	$14.100
• Tree Mortality Non-Bypassable Charge BA 2022 True-Up	-$38.634	-$38.634
• BioMAT Non-Bypassable Charge BA 2022 True-Up	-$4.725	-$4.725
Total Delivery Service	**-$433.184**	**-$428.820**

6.2.1. New System Generation and System Reliability F&PP

The New System Generation BA records the benefits and costs of power purchase agreements associated with new generation resources (*see* Section 5.3 for a discussion of applicable contracts). SCE identifies that most of the contracts from 2006 and 2007 whose costs are recorded in the New System Generation BA are terminating in 2023, which lowers the revenue requirements associated with this portion of CAM recovery.[111] With regard to System Reliability Request for Offer contracts, SCE states that because the Commission had not at the time of its October Update approved SCE's Advice Letter 4831-E (which would finalize the implementation details of the Modified CAM), SCE did not include the costs associated with this procurement in the 2023 ERRA Forecast revenue requirement and continues to track those costs in the System Reliability Procurement Memorandum Account (SRPMA).[112] SCE states that if it receives approval of Advice Letter 4831-E before December 1, 2022, it will include

[111] Exhibit SCE-05C at 104.

[112] *Id.* at 38 and 92.

implementation of the cost recovery concurrent with the Advice Letter implementing the 2023 ERRA Forecast rates.[113] SoCal CCAs state that they do not oppose SCE's proposal to include implementation of the cost recovery concurrent with the Advice Letter implementing the 2023 ERRA Forecast rates if Advice Letter 4831-E is approved before December 1, 2022.[114]

In D.20-06-002, the Commission established a central procurement framework, through which named CPEs will enter into contracts for RA starting in 2023. SCE is named as the CPE for its distribution service territory. SCE has included administrative costs and other costs associated with its role as CPE, such as system-related costs in the Centralized Local Procurement Sub-Account (a subaccount of the New System Generation BA).[115]

SCE estimates the 2022 year-end balance of the New System Generation BA is an undercollection of $97.951 million.[116] SCE states the undercollection is primarily the result of higher-than-forecast local capacity requirements and CHP resource costs.[117]

No parties opposed SCE's proposed revenue requirement for New System Generation and System Reliability contracts. Upon consideration, we find SCE's total requested revenue requirement for New System Generation and System Reliability contracts, along with SCE's request to true-up the New System Generation BA, reasonable and in compliance with applicable rules, orders and Commission decisions.

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[113] *Id.* at 110-111 fn. 112.

[114] SoCal CCAs Opening Brief at 10.

[115] *Id.* at 105.

[116] *Id.* at 94.

[117] *Ibid.*

6.2.2. Spent Nuclear Fuel

SCE forecasts $4.740 million in costs in 2023 for interim spent nuclear fuel storage as discussed in Section 5.6 above.[118]

No parties opposed or commented on this matter. We find SCE's 2023 forecast of $4.740 million for interim spent nuclear fuel storage costs reasonable and in compliance with applicable rules, orders and Commission decisions.

6.2.3. Base Revenue Requirement BA

The distribution subaccount of the Base Revenue Requirement BA records the costs associated with SCE's demand response programs, as discussed in Section 5.8 above.

No parties opposed or commented on this matter. Upon consideration, we find SCE's 2023 forecast credit of $11.473 million for costs tracked in the Base Revenue Requirement BA in compliance with applicable rules, orders and Commission decisions.

6.2.4. GHG Allowance Revenue Return

SCE requests the GHG allowance revenue return for the Emissions-Intensive and Trade-Exposed (EITE) customer return, the small business return and the residential California Climate Credit as a sum total of $777.564 million through its delivery service revenue requirement. Upon review, we find that SCE erred in calculating its forecast net GHG allowance revenue total by calculating the SOMAH funding true-up as a credit when it should have been a debit. As discussed in Section 7.4.1, the SOMAH program was

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[118] *Id*. at 114.

underfunded, which should result in a true-up debit instead of a credit. We correct the GHG allowance revenue to be $773.198 million to address the SOMAH funding true-up calculation error.

Upon consideration, we find SCE's corrected GHG allowance revenue reasonable and in compliance with applicable rules, orders and Commission decisions.

6.2.5. Public Purpose Program Charge

SCE forecasts a total 2023 revenue requirement of $70.144 million for the Tree Mortality Non-Bypassable Charge, the PRP #2, and the BioMAT program, as discussed in Section 5.4 above.[119] The total 2023 revenue requirement also includes the costs for volumetric subsidies under the DAC-GT and CSGT programs, as discussed in Section 7.4.2.

SCE also requests to return an estimated $38.634 million 2022 year-end balance in the Tree Mortality Non-Bypassable Charge BA as well as an estimated $4.725 million in 2022 year-end balance in the BioMAT Non-Bypassable Charge BA.

No parties opposed or commented on SCE's set-aside for Public Purpose Program Charge. After considering the matter, we find SCE's request to recover the $14.100 million for Public Purpose Programs through its 2023 revenue requirement, and to true-up its year-end balance for the Tree Mortality Non-Bypassable Charge BA and BioMAT Non-Bypassable Charge BA, as set forth in this ERRA forecast decision reasonable and in compliance with applicable rules, orders and Commission decisions.

[119] *Id*. at 11.

7. GHG Forecast Costs, Revenues and Reconciliation

The Commission adopted standard procedures for electric utilities to request GHG forecast revenue and reconciliation requirements filed after 2013 in D.14-10-033. The decision also adopted Confidentiality Protocols for Cap-and-Trade-related data and required the utilities to use a proxy price in their forecasts. Finally, the decision required the utilities to file GHG Forecast Revenue and Reconciliation Applications annually as part of their ERRA forecast applications. We use the standards adopted in D.14-10-033 to review SCE's current Forecast Application to determine the reasonableness of both the recorded and forecast variables.[120]

Rulemaking (R.) 20-05-002 reviewed the customer climate credits the State of California provides through the California Air Resources Board's (CARB) Cap-and-Trade Program and adopted revisions to ensure that the credits were compliant with current statutes and regulations, and streamlined certain existing processes. In D.21-08-026, the Commission determined that the volumetric dispersion of the small business California Climate Credit did not comply with CARB's Cap-and-Trade Regulation. To bring the small business return into compliance, starting in 2022 the Commission modified the small business California Climate Credit methodology to a flat rate approach mirroring and equal in size to the residential California Climate Credit.

SCE AL 4587-E-A/E-B/E-C developed new D-series templates to calculate credit amounts accounting for the methodological adjustments in D.21-08-026.

[120] Previously, the variables included Recorded and Forecast Volumetric Residential Return. However, in D.15-07-001, the Commission concluded that "The IOUs 2016 ERRA Forecast Filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016."

Template D-4 and Template D-5, previously submitted as part of the ERRA application, were removed.

SCE forecasts $452.317 million in GHG Cap-and-Trade costs for 2023.[121] SCE calculates the net GHG allowance revenues available for customer return at $777.564 million.[122] SCE's net GHG revenues consist of the following: (1) forecast GHG auction allowance revenues; (2) a true-up from the 2022 overcollection in GHG allowance revenue; (3) administrative and customer outreach expenses; (4) expenses for approved incremental clean energy and energy efficiency projects which may be funded by GHG allowance revenue; and (5) FF&U.

SCE proposes to distribute $40.416 million to EITE customers through the EITE customer return and $737.147 million to residential and small commercial customers through the California Climate Credit.[123] Finally, SCE proposes to return a semi-annual residential California Climate Credit of $71 per eligible account.[124]

Upon review of SCE's application, we find that SCE incorrectly calculated a $2.183 million SOMAH program true-up underfunding as a credit instead of a debit. We correct SCE's calculation error, which adjusts the net GHG allowance revenues available for customer return to $773.198 million, and the residential and small business distribution to $732.782 million. The Commission therefore finds SCE's GHG allowance-related revenues and expenses, as corrected herein, reasonable and in compliance with applicable rules, orders and Commission decisions.

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[121] Exhibit SCE-05C at 62.

[122] *Id.* at 92.

[123] *Ibid.*

[124] *Ibid.*

A summary of SCE's proposed GHG allowance-related revenues and expenses, along with the Commission's adopted GHG allowance-related revenues and expenses (as adjusted for the SOMAH funding true-up correction), are provided in Table 7-1 below:

Table 7-1. Summary of GHG Allowance Auction-Related Revenues and Expenses[125]

Program	SCE Proposed (millions)	Commission Adopted (millions)
GHG auction revenues		
1. 2022 GHG Auction revenue true-up	-$82.397	-$82.397
2. 2023 Forecast GHG auction allowance revenue	-$737.064	-$737.064
3. 2023 Forecast FF&U	-$8.244	-$8.244
GHG Revenue Subtotal	-$827.705	-$827.705
Administrative Expenses		
1. 2022 Outreach and Administrative Expenses	$0.325	$0.325
2. 2022 Forecast FF&U	$0.004	$0.004
Subtotal	$0.330	$0.330
Clean Energy and Energy Efficiency Programs ($ GHG Allowance Funding/$ PPP Funding[126])		
1. SCE 2023 SOMAH	$46.528/$0	$46.528/$0
2. SCE 2022 SOMAH True-Up	-$2.183/$0	$2.183/$0
3. SCE 2023 Disadvantaged Communities — Single-family Solar Homes (DAC-SASH)	-$4.600/$0	-$4.600/$0
4. SCE 2023 DAC-GT and CSGT	$0/$0	$0/$0
5. CPA 2023 DAC-GT and CSGT	$0.313/$2.281	$0.313/$2.281
6. Cal Choice 2023 DAC-GT and CSGT	$0.154/$0.625	$0.154/$0.625

[125] *Id.* at 92.

[126] *Id.* at 88-89.

Program	SCE Proposed (millions)	Commission Adopted (millions)
7. SCE Clean Energy Optimization Pilot (CEOP)	$0.400/$0	$0.400/$0
Total Clean Energy and EE Program Set-Asides	$49.813/$2.906	$54.178/$2.906
Total GHG Allowance Returns	-$777.564	-$773.198
1. EITE Customer Return	-$40.416	-$40.416
2. California Climate Credit	-$737.147	-$732.782

7.1. GHG Costs

GHG emissions costs are incurred directly or indirectly by a utility as a result of the GHG Cap-and-Trade program. Direct costs include, generally, the costs incurred to purchase compliance instruments for plants run by the utility or the costs of providing physical or financial settlements specifically for GHG emissions from plants not owned or operated by the utility. Indirect costs generally reflect GHG costs embedded in the price of power purchased on the market or through contracts that do not include GHG settlement terms.

SCE's October Update forecasts $452.317 million for direct GHG costs in 2023.[127] SCE calculates direct GHG costs by multiplying the 2023 forecast price of $30.26/metric ton (MT), which is the Intercontinental Exchange settlement price as of August 26, 2022, by the forecast GHG emissions volume for non-imported power.[128] SCE forecasts GHG emissions costs associated with imported power by taking the volume of energy SCE expects to generate or buy by resource type and multiplying by the emissions intensity for each resource type.[129]

[127] *Id*. at 6.

[128] *Id*. at 80.

[129] *Id*. at 54.

SCE's Forecast Application proposes to allocate direct GHG costs to the customers who receive a benefit from the resources to which the GHG costs are attributable. SCE includes the direct cost of the GHG compliance instruments in its proposed generation service though the ERRA BA, PABA and the Energy Settlement MA, as shown in Table 6-2. SCE also proposes to include direct GHG costs for the New System Generation BA through its delivery service, as shown in Table 6-3.

No parties opposed or commented on SCE's GHG costs. Upon review, the Commission finds SCE's 2023 forecast GHG costs reasonable and in compliance with applicable rules, orders and Commission decisions.

7.2. GHG Allowance Proceeds

GHG allowance revenue comes from the sale of GHG allowances allocated by the State of California for the benefit of ratepayers, which SCE sells on behalf of ratepayers at quarterly GHG allowance auctions. SCE forecasts its GHG allowance revenue by multiplying a proxy GHG allowance price of $30.26/MT by the total volume of allowances CARB allocated to SCE (24,357,709 allowances) in 2023.[130] SCE's total forecast GHG allowance revenue in 2023 is $737.064 million. SCE adjusts this forecast to reflect: (1) a refund of $82.397 million for an overcollection in the GHG Revenue BA during 2022; and (2) a refund of $8.244 million in FF&U in 2023, for a final 2023 GHG allowance revenue forecast of $827.705 million.[131]

No parties opposed or commented on SCE's GHG proceeds calculations. Upon consideration, the Commission finds SCE's net 2023 forecast allowance

[130] *Id.* at 92.

[131] *Ibid.*

proceed amount reasonable and in compliance with applicable rules, orders and Commission decisions.

7.3. Administrative and Customer Outreach Expenses

The recorded and forecast administrative and customer outreach expenses are the costs incurred by a utility for administrative and customer outreach expenditures that relate to the GHG allowance proceeds return program.

SCE's 2022 recorded administrative and customer outreach costs were $325,274.[132,133] SCE's 2023 forecast of administrative and customer outreach expenses is $325,000, consisting primarily of costs associated with the April and October residential Climate Credit bill inserts.[134] SCE also forecasts $3,635 in FF&U, for a total cost of $328,635 for administrative and customer outreach costs.[135]

No parties opposed or commented on SCE's 2023 forecast of administrative and customer outreach expenses. Upon consideration, the Commission finds SCE's 2023 forecast administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission decisions.

7.4. Clean Energy and Energy Efficiency Projects

Under Pub. Util. Code Section 748.5(c), the Commission may allocate up to 15% of the revenue received by an electric corporation from its sales of allocated GHG allowances to specific clean energy and energy efficiency projects that are

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[132] *Id.* at 92.

[133] Recorded administrative and customer outreach costs for 2022 were $328,912 including FF&U.

[134] Exhibit SCE-05C at 82.

[135] *Id*. at 92.

not funded by another source and are already approved by the Commission. SCE's total request for clean energy and energy efficiency projects is $49.813 million.[136] A summary of SCE's proposed clean energy and energy efficiency programs is provided in Table 7-1 above and discussed in Section 7.4.1 (SOMAH), Section 7.4.2 (DAC-SASH, DAC-GT, and CSGT), and Section 7.4.3 (CEOP).

7.4.1. SOMAH

AB 693 (Eggman), Stat. 2015 ch. 582, created the SOMAH program, allocating 10% of auction proceeds up to $100 million annually, whichever is less, for fiscal years 2016 through June 2026 in funding from Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), SCE, Liberty Utilities (CalPeco Electric) LLC (Liberty) and PacifiCorp d/b/a Pacific Power's (PacifiCorp) share of GHG allowance auction proceeds to install solar photovoltaic systems on multifamily affordable housing throughout California.[137] SCE set aside funding for SOMAH starting in 2017 and the SOMAH program began operating on July 1, 2019. In D.17-12-022, the Commission required that 10% of forecast auction revenue be reserved for SOMAH through each IOU's ERRA applications and established that each IOU shall contribute its proportionate share of $100 million, when necessary, based on its share of allowance sale proceeds from the previous four quarters.[138]

In D.20-01-022, the Commission clarified that prior-year GHG revenue allocations should be trued-up based on a 10% allocation of actual GHG revenues received. In D.20-04-012, the Commission extended SOMAH through

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[136] *Ibid.*

[137] D.17-12-022.

[138] D.17-12-022 (OP 4 and OP 7).

June 2026, directed the IOUs to make SOMAH program funding available for the latter half of 2020 as part of their 2021 request for SOMAH program funding, clarified existing requirements, and set additional requirements for the SOMAH budget true-up process.[139]

The year 2021 was the first year that the combined IOUs' allocation of 10% of GHG allowance forecast revenues exceeded the $100 million amount for the SOMAH program. D.22-09-009 modified the forecast budgeting process, adding a pathway for each IOU to request to set aside their proportionate share of a $100 million budget and identified a set allocation for each IOU's share.[140] This pathway is dependent on their ability to adequately demonstrate that the IOUs' combined forecast GHG allowances will equal or exceed $1 billion.[141] Now IOUs may either propose setting aside 10% of their forecast revenue or their share of $100 million.

SCE anticipates the IOUs will collectively exceed the $1 billion amount based on SCE's estimate of the IOUs' total forecasts for 2023.[142] Table 7-2 provides the forecast GHG proceeds and the percent allocations required by D.22-09-009 to determine the forecast set asides for 2023. SCE proposes a total set aside of $46.528 million for SOMAH in 2023.

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139 The SOMAH program funding is allocated on a fiscal year basis while the Forecast revenue requirement is set for the calendar year, in this case 2022.

140 D.22-09-009 Table 1.

141 D.22-09-009 OP 3.

142 Exhibit SCE-05C at 84.

Table 7-2. Table of IOU Proposed PY2023 GHG Revenue Reallocation to Account for SOMAH Program $100 Million Annual Amount[143]

PY	**2023 Forecast GHG Proceeds ($000)**[144]	**D.22-09-009 Table 1 Percent Allocation SOMAH Allocation for $100 million amount (%)**	**D.22-09-009 Table 2 Amount for $100 million SOMAH Set-Asides**
PG&E	$491,898	39.75737884%	$39,757,378.84
SCE	$737,064	46.52785609%	$46,527,856.09
SDG&E	$191,140	12.01597192%	$12,015,971.92
PacifiCorp	$5,236	1.29882216%	$1,298,822.16
Liberty	$17,903	0.39997099%	$399,970.99
IOU Sum	**$1,443,241**	100.000%	$100,000,000

SCE proposes to true-up its current 2022 actual set-aside for SOMAH to $70.910 million.[145] Based on SCE's calculation of the total SOMAH program funding for 2016 through 2022, SCE calculates a net true-up amount for SOMAH of $2.183 million, as shown in Table 7-3, however, the final budget amount for SOMAH is not finalized until the calendar year has closed.[146] Upon review, we find that SCE erred when entering the true-up of amount of $2.183 million into Table VII-34/Template D-1 of its October Update. SCE entered a negative value, which would reflect an overfunding and therefore a credit, when in fact the entry should have been a positive value to reflect an underfunding. This decision corrects SCE's error, as discussed in Section 6.2.4. Due to SCE's use of a rounded value, the California Climate Credit remains $71. As per the SOMAH decisions

[143] *Id.* Table VII-31 at 85.

[144] *Ibid.*

[145] *Ibid.*

[146] *Id.* at 85.

mentioned above, we expect SCE will submit a revised and trued-up total for 2022 as part of its "Prior Year True-up" value in its next application.

Table 7-3. Table Summarizing the PY2022 SOMAH Program True-Up[147]

PY	Total GHG	10%/$100 million	ERRA Set-aside for PY	Difference
2016	$188,087,539	$18,808,754	$0	$18,808,754
2017	$384,894,152	$38,489,415	$8,077,000	$30,412,415
2018	$389,316,108	$38,931,611	$39,125,783	-$194,173
2019	$421,170,202	$42,117,020	$40,853,635	$1,263,386
2020	$420,965,536	$42,096,554	$73,281,647	-$31,185,111
2021[148]	$551,751,564	$49,498,366	$63,966,285	-$14,467,919
2022	$709,100,721	$70,910,072	$ 73,364,564	-$2,454,492
Total	**$3,065,285,646**	**$300,851,775**	**$298,668,914**	**$2,182,860**

No parties commented on SCE's proposed SOMAH allocation. Upon review, the Commission finds SCE's SOMAH allocation, as corrected herein, reasonable and in compliance with applicable rules, orders and Commission decisions.

7.4.2. DAC Programs

In D.18-06-027, the Commission created the DAC-SASH, DAC-GT, and CSGT programs to increase access to solar generation in low-income households. D.18-06-027 set an annual $10 million budget for the DAC-SASH program. SCE

[147] *Id.* Table VII-32 at 86.

[148] In 2021, the IOUs' combined revenue exceeded $1 billion. Each IOU's proportionate share of SOMAH's $100 million budget for that year was approved in a Joint IOU advice letter, AL 338-E PacifiCorp/AL 4828-E SCE, disposed with a standard disposition on July 14, 2022.

proposes to set-aside $4.600 million, its share of the annual $10 million budget, for the DAC-SASH program in 2023.[149]

D.18-06-027 set no budget for the DAC-GT or CSGT programs, but authorized IOUs to fund both programs first through available GHG allowance proceeds, and then through Public Purpose Program funds if the GHG allowance funds were exhausted. In 2021, CARB informed the IOUs that D.18-06-027's requirement to fund the 20 percent bill discount for DAC-GT and CSGT customers using GHG allowance funds was prohibited by Title 17, California Code of Regulations (C.C.R.) Section 95892(d)(7)(D), which prohibits "returning allocated auction proceeds to ratepayers in a volumetric manner" where the term "volumetric" is defined as "describ[ing] an electrical distribution utility's or natural gas supplier's direct distribution of allocated allowance auction proceeds to one or more of its ratepayers based on the current and recent amount of electricity, natural gas, or other relevant utility service delivered to those ratepayers, such that higher usage results in ratepayers' receipt of more funds" pursuant to Title 17, C.C.R. Section 95802.[150] According to SCE, CARB also clarified that this prohibition also applies to information technology upgrades and marketing costs supporting the administration of volumetric returns.[151] SCE states that beginning with its 2022 ERRA forecast rates, it is now separately tracking DAC discounts and related costs and recovering those amounts through its Public Purpose Program rates.[152]

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[149] Exhibit SCE-05C at 92.

[150] SCE AL 4613-E; Energy Division Disposition Letter for SCE AL 4613-E (November 15, 2021).

[151] Exhibit SCE-05C at 86-87.

[152] *Id.* at 87.

SCE states that it does not require additional GHG funding for its DAC programs in 2023 because it has sufficient set aside to cover forecast costs.[153]

D.18-06-027, as clarified by Resolution E-4999, authorized CCAs to access these same program funding sources to run their own DAC-GT and CSGT programs. CPA and the Joint CCAs (which includes CalChoice, Pico Rivera Innovative Municipal Energy, and San Jacinto Power) have received approval to run their own DAC-GT and CSGT programs.

The volumetric limits on GHG funding also apply to CCA programs. As such, SCE's application includes a GHG funding set-aside of $0.313 million in 2023 for CPA's DAC-GT and CSGT, with $2.281 million proposed to be recovered through Public Purpose Program funds.[154]

SCE also includes a GHG funding set-aside of $0.154 million in 2023 for the Joint CCAs, with $0.625 million proposed to be recovered through Public Purpose Program funds.[155]

No parties commented on SCE's set aside for the DAC programs. Upon consideration, the Commission finds SCE's set aside for DAC-SASH, DAC-GT and CSGT reasonable and in compliance with all rules, law and Commission orders. DAC-GT and CSGT program costs related to: (1) the 20% bill discount; (2) all administrative costs; (3) information technology costs; and (4) marketing, education and outreach costs that are properly recorded in the Public Purpose Program Adjustment Mechanism, and recovered through the Public Purpose Programs Charge. Other DAC-GT and CSGT program costs are properly funded

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[153] *Ibid.*

[154] *Id*. at 88.

[155] *Id*. at 88-89.

through GHG allowance revenue available under the 15% allowance for clean energy and energy efficiency projects.

7.4.3. Clean Energy Optimization Pilot (CEOP)

D.19-04-010 approved $20.4 million for the CEOP pilot, a pay-for-performance model energy-efficiency pilot at University of California (UC) and California State University (CSU) schools. The CEOP pilot period began in July 2019. SCE's 2020 ERRA forecast requested $10 million for the CEOP pilot, which was approved in D.20-01-022. Nine months after the start of the CEOP pilot, due to Governor Newsom's March 19, 2020 stay-at-home order necessitated by the COVID-19 pandemic, the UC and CSU systems transitioned to remote learning, resulting in a significant depopulation of university buildings. In May 2020, the settling parties to the CEOP reconvened to discuss modifying the CEOP terms to address the greatly altered electricity use at UC and CSU schools and in August 2020 a PFM of D.19-04-010 was submitted. SCE's 2021 Forecast ERRA did not request additional funds for the CEOP pilot as the future of the program was unclear. In November 2020, the Commission approved a settlement modifying the original CEOP pilot agreement and allowing the CEOP to continue to move forward.[156]

D.22-01-003 authorized an additional $10 million in funding for the CEOP in 2022. Since SCE previously set aside $10 million in the 2020 and 2022 ERRA Forecasts[157] (and $0 million in the 2021 ERRA forecast),[158] there is a remaining budget of $0.4 million authorized for the CEOP. Accordingly, SCE's request is

[156] D.20-11-030.

[157] D.20-01-022 at 51.

[158] D.20-12-035 at 39.

consistent with all rules, law and Commission orders and this Decision approves SCE's request to set aside $0.4 million in funding for the CEOP in 2023.

7.5. EITE Emissions Customer Return

A portion of the GHG allowance proceeds is returned to customers who qualify as EITE. The EITE customer return is set by formula and made to qualifying customers once per year in April.

SCE's 2022 recorded EITE customer return was $40.416 million and SCE's 2023 forecast EITE customer return is $40.416 million.[159]

No parties opposed or commented on SCE's 2023 forecast EITE customer return as proposed in the October Update. Upon consideration, the Commission finds SCE's forecast 2023 EITE customer return reasonable and in compliance with applicable rules, orders and Commission decisions.

7.6. California Climate Credit

The California Climate Credit is distributed to residential and small commercial accounts after all applicable GHG-related expenses and other customer returns have been made. It appears as a credit on applicable residential and small commercial customers' bills twice a year in April and October. The California Climate Credit is not related to the volume of electricity used by the applicable account; each residential or small commercial account within a utility's territory receives the same California Climate Credit.

In 2022, the total recorded GHG allowance revenue was approximately $82.397 million more than forecast for 2022.[160] SCE proposes to return the 2022 overcollection through the total 2023 GHG allowance revenue available for distribution through the California Climate Credit.

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[159] Exhibit SCE-05C at 92.

[160] *Ibid.*

SCE's 2023 forecast of the total number of households and small businesses eligible for the California Climate Credit is 5,160,130 and the proposed total revenue available for the Climate Credit is $737.147 million.[161] SCE proposes a California Climate Credit of $71, to be distributed as a credit on residential and small commercial account customers' bills in April and October of 2023.[162]

No parties opposed or commented on SCE's California Climate Credit in the October Update. As discussed in Section 6.2.4 and Section 7.4.1, this decision corrects a SOMAH funding true-up calculation error, which results in the total GHG allowance revenue available for customer return changing from $737.147 million to $732.782 million. The residential and small business California Climate Credit remains unchanged at $71. Upon consideration, the Commission finds SCE's forecast 2023 California Climate Credit, as corrected herein, reasonable and in compliance with applicable rules, orders and Commission decisions.

8. Cost Responsibility Surcharges

The Cost Responsibility Surcharge Indifference Amount[163] is the difference between the total portfolio cost and the forecast value of the portfolio; it includes the CTC and the PCIA charges. We find SCE's Cost Responsibility Surcharge rates to be reasonable and they are approved as modified below. The CTC charge is discussed in Section 8.1. Charges for the Wildfire Fund Non-Bypassable Charge are discussed in Section 8.2. PCIA charges are discussed in Section 8.3.

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[161] *Ibid*.

[162] *Ibid*.

[163] The Commission adopted the Cost Responsibility Surcharge Indifference Charge in D.02-11-022, as modified by D.03-07-030, D.06-07-030, D.08-09-012, D.11-12-018, Resolution E-4475, D.18-10-019 and D.19-10-001, and D.21-03-051.

8.1. CTC Surcharge

The CTC surcharge recovers the "above-market" charges for pre-restructuring resources and is the same for each customer class regardless of a customer's departure date. For 2023, SCE forecasts the following CTC costs: (1) $0.00007/kWh for Domestic (D) customers of all vintages; (2) $0.00006/kWh for St. Lighting customers of all vintages; (3) $0.00005/kWh for TOU-GS-1, TC-1, TOU-GS-2, TOU-GS-2, TOU-8-Sec, TOU-8-Pri, TOU-PA-2, TOU-PA-3, Standby-Sec, Standby-Pri customers of all vintages; and (4) $0.0004/kWh for TOU-8-Sub and Standby-Sub customers of all vintages.[164]

8.2. Wildfire Fund Non-Bypassable Charge

The Wildfire Non-Bypassable Charge helps fund the Wildfire Fund, which is an insurance fund that allows recovery for prudently incurred utility wildfire costs and provides financial stability to California's electrical corporations.[165] The Wildfire Fund Non-Bypassable Charge replaced the CDWR Bond Charge, which expired on September 30, 2020.[166] For 2023, SCE forecasts the Wildfire Non-Bypassable Charge has a cost of $0.00652/kWh for all customer classes in all vintages.[167]

8.3. PCIA Surcharge

The PCIA recovers the above-market costs of all non-CTC eligible resources and varies by the generation resources in that vintage. PCIA costs are assigned by customer vintage year, which is determined by the date of a customer's departure from bundled customer service. Customers who depart in

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[164] Exhibit SCE-05C at Appendix B.

[165] D.20-10-056.

[166] D.20-09-005.

[167] Exhibit SCE-05C at Appendix B.

the first half of each year are assigned to the prior year's vintage and customers who depart in the second half of each year are assigned to the current year's vintage.[168] For example, 2019 vintage departing load customers are those who departed SCE's bundled customer service between July 1, 2019 and June 30, 2020. SCE's vintages include 2001-2003, 2004-2008, and annually starting in 2009.

In order to calculate its PCIA requirement, SCE first calculates the "above market" or "below market" costs of its portfolio, also called the Indifference Amount. Accounting for true-ups and adjustments, SCE calculates a total 2023 PCIA revenue requirement of $155.956 million, $156.237 million including the Uncollectibles factor.[169] SCE's forecast of its 2023 PCIA requirement is summarized in Table 8-1.

Table 8-1. Summary of Proposed 2023 Portfolio Costs, Portfolio Market Value, Balancing Account True-Ups, and Total PCIA Revenue Requirement Based on October Update Testimony[170]

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	$4,132.129
Market Value	$4,640.604
• Energy Value	$3,417.991
• RPS Value	$353.036
• RA Value	$869.577
One-Time Adjustments	-$1.543

[168] D.08-09-012 at 108 (OP 9).

[169] As discussed further in Section 8.3.1, SCE has previously used the entire FF&U factor to gross-up PCIA rates. In the October Update to its 2023 ERRA Forecast Application, SCE proposes to apply only the Uncollectibles Factor in the PCIA gross-up, in order to correct a double-assessment of the Franchise Fee Factor on departed load customers' PCIA rates that the Southern California CCAs identified. (*See* Exhibit SCE-04 at 4.)

[170] Exhibit SCE-05 at 116.

PCIA Revenue Requirement	Amount (millions)
Total 2023 Indifference Amount	-$510.018
Balancing Account True-Ups (no Uncollectibles Factor)	
• 2022 YE PABA Balance	-$156.357[171]
• 2022 GRC Memo Account (27-Month Amortization)	-$3.525
• 2022 YE ERRA Balance	$825.855[172]
2023 PCIA Revenue Requirement	$155.956
2023 PCIA Revenue Requirement with Uncollectibles Factor	$156.237

For 2023, SCE forecasts a total Indifference Amount of -$510.018 million, which is the Total Portfolio Cost[173] of $4,132.129 million less the $4,640.604 million Market Value[174] of SCE's portfolio. The negative Indifference Amount of -$510.018 million indicates that SCE's generation portfolio is "below market" for 2022, which requires a PCIA credit on departed load customers' bills and lower electricity rates for SCE's bundled service customers.

[171] -$156.639 million with the Uncollectibles Factor.

[172] $827.344 million with the Uncollectibles Factor.

[173] The Total Portfolio Cost is based on forecast fixed and variable costs of generation resources SCE forecasts it will use to meet bundled customer needs for the year. (Exhibit SCE-05 at 117.) These include the base generation revenue requirement determined in the GRC Phase 1, fuel costs, direct GHG costs of eligible UOG, RPS-eligible contract costs, QF and non-CAM-eligible CPH contract costs, all bilateral and RFO contract costs (including fuel costs and direct GHG costs as applicable), and one-time refunds or adjustments. (Exhibit SCE-05 at 117-118.) The Total Portfolio Cost does not include any costs associated with CAM or Local Capacity Requirement-eligible resources, the Tree Mortality Non-Bypassable Charge BA, BioMAT Non-Bypassable Charge BA, ISO-load related costs, or Residual Net Position spot market (*i.e.*, "short term") purchases. (Exhibit SCE-05 at 118.)

[174] The Market Value of SCE's portfolio is calculated as a sum of the energy value, the RPS value, and the RA value of the portfolio. For each variable, a market price benchmark is multiplied by the applicable volume of the value calculated.

After calculating the Indifference Amount, SCE calculates the total PCIA revenue requirement by accounting for applicable balancing account true-ups and other adjustments, including: (1) annual true-ups in the ERRA BA and PABA; (2) the amortization of the final third of the 2020 PUBA undercollection in 2023; and (3) updates to SCE's revenue requirement in the Authorized Generation Base Revenue Requirement[175] in SCE's 2021 Track 1 GRC proceeding, A.19-08-013.

In D.18-10-019, the Commission adopted a cap that limited the year-over-year change in PCIA rates. Beginning in forecast year 2020, "the cap level of the PCIA rate [was] set at 0.5 cents (¢)/kWh more than the prior year's PCIA, differentiated by vintage."[176] As a result, if the system average PCIA rate by customer vintage was forecast to increase by more than 0.5¢/kWh, then all PCIA rates for that customer vintage were capped. In D.21-05-030, the Commission removed the PCIA rate cap and trigger mechanism and, in relevant part, ordered SCE to address its projected 2021 year-end PCIA cap under-collection account balance in its 2022 ERRA forecast application (A.21-06-003).[177]

SCE proposes to collect $20.299 million in 2023, in accordance with D.20-12-035, which directed SCE to collect the 2020 PUBA undercollection over a three-year amortization period in 2021, 2022, and 2023.[178] The $20.299 million

[175] The base generation rate revenue requirement includes the costs of operating, maintaining, and investing in SCE's generation, distribution and general functions, and excludes costs for fuel and power.

[176] D.18-10-019.

[177] D.21-05-030 at 63 (OP 1).

[178] Exhibit SCE-05-E at 120.

amortization amount is included in SCE's proposed PCIA rates for 2023, which are summarized in Table 8-2.

Table 8-2. Summary of Proposed 2023 System Average PCIA Rates[179]

PCIA Vintage Year	2023 PCIA Rates, System Average ($/kWh)
2001	-0.00003
2004	-0.00003
2009	0.00028
2010	0.00027
2011	0.00056
2012	0.00051
2013	0.00002
2014	-0.00267
2015	-0.00625
2016	-0.00663
2017	-0.00772
2018	-0.00679
2019	-0.01116
2020	-0.01001
2021	-0.01110
2022	0.00703
2023	0.00529

SoCal CCAs assert that SCE erroneously excluded the capacity from an RA contract from the calculation of Retained RA value for the purposes of

[179] Exhibit SCE-05 at B-8.

calculating the 2023 Indifference Amount.[180] Upon review, SCE confirms that this contract was erroneously omitted and agrees it should be included.[181] Correcting this error adds $1.348 million (without Uncollectibles) in local RA value to the 2023 Indifference Amount. Separately, SCE also identifies that in its October Update, it used the flexible capacity value for certain Mid-Term Reliability energy storage resources in its workpapers.[182] The flexible capacity value is two times the net qualifying capacity value. SCE recommends correcting this approach to cap the flexible capacity for these resources at their net qualifying capacity values, in alignment with the definition of flexible capacity adopted in D.18-10-019. [183] Making this correction would remove $24.017 million (without Uncollectibles) in flexible RA value from the 2023 Indifference Amount. We find it reasonable to update the numbers to correct these two errors and do so here in this decision. Correcting these two errors results in a net decrease to the 2023 Indifference Amount of $22.669 million (without Uncollectibles). We therefore adopt the resulting values in Table 8-3 and Table 8-4.

Table 8-3. Summary of Adopted 2023 Portfolio Costs, Portfolio Market Value, Balancing Account True-Ups, and Total PCIA Revenue Requirement

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	$4,132.129
Market Value	$4,617.935
• Energy Value	$3,417.991
• RPS Value	$353.036
• RA Value	$846.908

[180] Exhibit CCA-05 at 1.

[181] *Ibid.*

[182] SCE Reply Brief at 3 and Exhibit CCA-06 1-2.

[183] SCE Reply Brief at 3.

PCIA Revenue Requirement	Amount (millions)
One-Time Adjustments	-$1.543
Total 2023 Indifference Amount	-$485.806
Balancing Account True-Ups (no Uncollectibles Factor) • 2022 YE PABA Balance • 2022 GRC Memo Account (27-Month Amortization) • 2022 YE ERRA Balance	 -$156.357[184] -$3.525 $825.855[185]
2023 PCIA Revenue Requirement	$178.625
2023 PCIA Revenue Requirement with Uncollectibles Factor	$178.947

Table 8-4. Summary of Adopted 2023 System Average PCIA Rates

PCIA Vintage Year	2023 PCIA Rates, System Average ($/kWh)
2001	-0.00003
2004	-0.00003
2009	0.00028
2010	0.00027
2011	0.00056
2012	0.00051
2013	0.00002
2014	-0.00267
2015	-0.00625
2016	-0.00663
2017	-0.00772
2018	-0.00679

184 -$156.639 million with the Uncollectibles Factor.

185 $827.344 million with the Uncollectibles Factor.

PCIA Vintage Year	2023 PCIA Rates, System Average ($/kWh)
2019	-0.01116
2020	-0.01001
2021	-0.01062
2022	0.00750
2023	0.00566

8.3.1. Franchise Fee Assessment on Departing Load Customers

SCE collects Franchise Fees from bundled and unbundled customers. SoCal CCAs identify that SCE's current approach to collecting Franchise Fees from departing load customers results in a double assessment of the Franchise Fee Factor on departing load customers' PCIA rates — first as a result of the Franchise Fee gross-up on the PCIA revenue requirement and second as a result of their payment of the Generation Municipal Surcharge rate.[186] To resolve this, SoCal CCAs propose that SCE cease to gross-up the PCIA revenue requirement with the Franchise Fee Factor. [187] SCE agrees with SoCal CCAs' assertion that its current approach results in an overcharge and agrees with SoCal CCAs' proposed approach to resolving the overcharge.[188] SCE implements this change as part of its October Update testimony. SCE believes that in order to effectuate SoCal CCAs' recommended change, the Commission would need to authorize SCE to modify the relevant tariff, as approach SCE had been using was in

[186] Exhibit CCA-01 at 15.

[187] *Id.* at 18.

[188] Exhibit SCE-04C at 4.

accordance with the authorized tariff.[189,190] SCE therefore requests the Commission authorize it to modify its relevant tariff to cease gross-up of the PCIA revenue requirement with the Franchise Fee Factor.[191]

We agree with SoCal CCAs and SCE that SCE's current approach to collecting franchise fees from departing load customers results in an overcharge and find that SCE should cease to gross-up the PCIA revenue requirement with the Franchise Fee Factor to resolve the overcharge. We therefore direct SCE to update its Preliminary Statement WW to cease to gross up the PCIA revenue requirement with the Franchise Fee Factor and to submit the revised tariff as part of its Advice Letter implementing the 2023 ERRA Forecast rates.

8.3.2. Voluntary Allocation Market Offer (VAMO) Process

The Commission adopted the VAMO process for PCIA-eligible RPS resources in D.21-05-030. SCE has developed a three-step process to value RECs included in its PABA portfolio: (1) calculate RECs that were elected by parties during the Voluntary Allocation process; (2) assume unallocated RECs are offered via the Market Offer process; and (3) evaluate SCE's RPS position to meet the compliance requirements and determine if (and how many) RECs would be used from SCE's RPS bank.[192]

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189 *Ibid.*

190 We note that in its October Update testimony, SCE proposes to remove the Franchise Fee Factor and apply only the Uncollectibles Factor in the PCIA gross-up.

191 Exhibit SCE-04C at 4.

192 Exhibit SCE-05C at 122-123.

Because the Market Offer process had not yet been launched at the time SCE filed its October Update,[193] SCE assumed that 100% of the RECs remaining after the Voluntary Allocation process would be sold as part of the Market Offer process, and used the Forecast RPS Adder to value both the Voluntary Allocation-elected RECs and the estimated Market Offer-sold RECs.[194] SCE then assessed that it would be necessary to use its historical RPS bank to satisfy its 2023 RPS compliance requirements.[195] For the purposes of its 2023 forecast PCIA Indifference Amount, SCE applied the Forecast RPS Adder to the banked RECs that were previously valued at $0.[196]

SoCal CCAs agree with SCE's current methodology for valuing banked RECs in the PCIA Indifference Amount and believe the amounts were properly included in SCE's forecast.[197] SoCal CCAs also request the Commission order that a permanent methodology be developed in the PCIA proceeding (R.17-06-026).[198]

We find SCE's methodology for valuing banked RECs for the purposes of its 2023 forecast PCIA Indifference Amount to be reasonable. We also identify that the current scope of the PCIA proceeding includes consideration of whether

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[193] A proposed decision addressing Market Offer implementation was issued on September 29, 2022 in R.18-07-003, and had not been adopted by the Commission as of the issuance of this proposed decision.

[194] *Id.* at 123.

[195] *Ibid.*

[196] *Id.* at 123-124.

[197] SoCal CCAs Opening Brief at 18.

[198] *Id.* at 18-19.

to modify or clarify the calculation of the PCIA for VAMO transactions,[199] so we do not address SoCal CCAs' request here.

9. ERRA Trigger Mechanism Application

SCE's compliance with ERRA trigger mechanism filing requirements is discussed in Section 9.1. The accuracy of SCE's trigger application, the causes of the ERRA trigger-related undercollection, and the rate impact of the ERRA trigger application are discussed in Section 9.2.

9.1. SCE Complied with the ERRA Trigger Mechanism Filing Requirements

SCE's ERRA trigger point for 2022 is $202.471 million and its AB 57 threshold amount is $253.088 million.[200] SCE's ERRA trigger balance of $245.694 million, recorded on August 31, 2022, exceeded its ERRA trigger point. SCE's forecast year-end ERRA trigger-related balance was not expected to self-correct within 120 days.

SCE filed an ERRA trigger mechanism application on September 30, 2022. Since SCE filed an ERRA trigger mechanism application within a month of exceeding the ERRA trigger point, when its balance was not forecast to self-correct within 120 days, the Commission finds SCE timely filed the ERRA trigger mechanism application.

9.2. Components of SCE's Trigger Application

The Commission's latitude and range of review of ERRA trigger applications are proscribed by Pub. Util. Code Section 454.5(d)(3). This is

[199] Assigned Commissioner's Second Amended Scoping Memo and Ruling, R.17-06-026, Issued June 2, 2022.

[200] SCE AL 4729-E.

reflected in the review process the Commission established in D.02-10-062, which details the components of an ERRA trigger application, requiring:

> a projected account balance in 60 days or more from the date of filing depending on when the balance will reach the five percent threshold. The application will also propose an amortization period for the five percent of not less than 90 days to ensure timely recovery of the projected ERRA balance. It should also include allocation of the over- and undercollection among customers for rate adjustment based on existing allocation methodology recognized by the Commission.[201]

When reviewing a trigger application, the Commission must confirm the accuracy of SCE's estimates and confirm that those estimates meet the AB 57 threshold amount within the timeframes established by law in order to approve the application.[202] Where a rate increase is required to correct an undercollected revenue requirement, the Commission conducts a step-by-step review of the request in order to benefit SCE, its ratepayers and the protestants. The step-by-step review of SCE's trigger application includes the following: (1) the accuracy of the ERRA trigger-related balance request and requirement to meet the AB 57 threshold amount; (2) causes of the undercollection; (3) the rate impact of including the undercollection in SCE's rates; (4) allocation of the undercollection among SCE's customers; and (5) the amortization period of the undercollection.

[201] D.02-10-062 at 65-66.

[202] This is a similar review to the Commission's review for accuracy of SCE's ERRA BA in SCE's 2023 ERRA forecast proceeding.

9.2.1. Accuracy of the ERRA Trigger Application and Requirement to Meet the Trigger Point and AB 57 Threshold Amount

SCE's ERRA Trigger balance increased to $245.694 million as of August 31, 2022, as shown in Table 9-1.

Table 9-1. SCE's Recorded Values for ERRA Trigger Balance Calculation

Month	Adjusted ERRA Balance (millions)	Adjusted PABA Balance (millions)	Trigger Balance (millions)	Trigger as % of Generation Revenue
January 2022	$15.403	$390.478	$25.541	5.58%
February 2022	$126.807	$413.423	$412.819	8.07%
March 2022	$101.938	-$119.053	-$2.100	-0.04%
April 2022	$47.061	-$17.739	$31.560	0.62%
May 2022	$3.990	$80.020	$73.918	1.46%
June 2022	-$21.391	$171.873	$128.806	2.54%
July 2022	-$16.605	$22.143	$181.017	3.58%
August 2022	$88.859	-$179.468	$245.694	4.85%

SCE forecast an increasing ERRA Trigger balance for the next 120 days in order to determine whether the undercollection would self-correct, as shown in Table 9-2 below.

Table 9-2. SCE's Forecast Values for ERRA Trigger Balance Calculation

Month	Adjusted ERRA Balance (millions)	Adjusted PABA Balance (millions)	Trigger Balance (millions)	Trigger as % of Generation Revenue
September 2022	$178.721	$60.750	$231.809	4.58%
October 2022	$307.416	$73.824	$371.929	7.35%
November 2022	$445.848	-$16.891	$431.087	8.52%
December 2022	$717.859	-$188.040	$553.534	10.94%

The Commission is satisfied that parties were provided sufficient time to review the ERRA BA and PABA balances for inaccuracies. While the shortened timeframe imposed by statutes (combined with the uncertainties generally inherent in energy forecasting) create challenges for all parties in the ERRA process, parties have had the opportunity to review the ERRA BA and PABA balances. Therefore, the Commission finds that SCE first exceeded the four percent trigger point as of August 31, 2022, and the ERRA trigger balance was not expected to self-correct within 120 days.

9.2.2. Causes of the ERRA Trigger-Related Undercollection

SCE is required to explain the cause of any undercollection in its ERRA trigger application. SCE's testimony states that the primary driver of the undercollection is higher-than-expected market power prices, which resulted in a 19% increase in recorded costs in the ERRA BA.[203] SCE explains that actual year-to-date power prices are 12% higher than the forecast amount used to set the 2022 ERRA rates.[204] SCE argues that the higher-than-forecast power prices led to an undercollection in the ERRA BA, which SCE uses primarily to record short-term market costs procured on behalf of its bundled service customers. SCE also attributes the undercollection to higher-than-expected bundled customer load.[205]

According to SCE, market conditions also impacted the PABA to a lesser degree. SCE states that higher market prices resulted in increased market

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[203] Exhibit SCE-01-Trigger at 10-11.

[204] *Id*. at 12.

[205] *Id*. at 10.

revenues from SCE's long-term, fixed-price contracts and utility-owned generation, which SCE records in the PABA. SCE also states that increased revenue was, to some extent, offset by higher than projected gas prices resulting from supply interruptions, geopolitical turmoil associated with Russia's invasion of Ukraine and weather-related gas demand nationally.[206] SCE explains that the average forecast price for natural gas was 47% higher than SCE's 2022 forecast gas price.[207] This decision finds SCE's explanation of the causes for its ERRA trigger point exceedance on August 31, 2022 reasonable.

9.2.3. Rate Impact and Allocation of Undercollection

SCE states that its ERRA Trigger Balance will fall below the trigger point and threshold when it implements its 2023 ERRA Forecast rates because the recovery of final 2022 year-end balances, which includes the ERRA Trigger Balance, are put into rates as part of the 2023 ERRA Forecast rate implementation.[208] SCE therefore requests the Commission either: (1) maintain ERRA-related rates at their current levels until January 2023 and adjust rates to recover the ERRA Trigger Balance starting in January 2023, concurrent with rate adjustments to implement the ratemaking proposed in SCE's 2023 ERRA Forecast application; or (2) maintain ERRA-related rates at their current levels until January 2023 and dismiss the ERRA Trigger Application as moot in light of the pending ERRA Forecast application.

SCE calculates that a 12-month amortization of the $245.694 million ERRA BA undercollection would increase rates by an average of 2.1¢/kWh, with

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[206] *Id*. at 14.

[207] *Ibid*.

[208] *Id*. at 1.

an estimated average residential bill impact of 1.8%, which is an average monthly bill increase of $2.74 for non-CARE residential customers and $1.85 for CARE customers.[209,210]

While it is reasonable to allow SCE to separately amortize its undercollection, we find that it is not necessary in this instance because this decision achieves the same cost recovery by authorizing SCE's 2023 ERRA Forecast rates, which will include the undercollection identified in the 2022 year-end ERRA Trigger Balance. This decision does grant SCE's request to maintain ERRA-related rates at their current levels until it implements its 2023 ERRA Forecast rates.

10. Public Comments

Pursuant to Rule 1.18(a) of the Commission's Rules of Practice and Procedure (Rules),[211] all written public comments submitted in a proceeding that are received prior to the submission of the record will be entered into the administrative record of that proceeding. Pursuant to Rule 1.18(b), relevant written comment submitted in a proceeding will be summarized in the final decision issued in the proceeding.

Prior to the submission of the record in this combined proceeding, 17 public comments were entered into the administrative record and are available for review in the public comments tab of the docket card for the combined proceeding. The public comments express opposition to SCE's

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[209] *Id.* at 11.

[210] While SCE provides forecast rate impact based on the August Trigger amount, SCE forecasts an undercollection in the ERRA BA at the end of the year of approximately $553.534 million, as identified in Table 9-3.

[211] On May 1, 2021, the Commission revised its Rules to formally incorporate public participation into the Commission's decision-making process.

proposed rate increase. No parties to this proceeding responded to, or cited, the public comments in their submissions to the Commission, as allowed by newly adopted Rule 1.18(b). No further party comment was solicited in this proceeding pursuant to Rule 1.18(d).

11. Safety Considerations

The health and safety impacts of GHGs are among the reasons that the Legislature enacted AB 32. Specifically, the Legislature found and declared that global warming caused by GHGs "poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." Potential adverse impacts include "the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious disease, asthma, and other human health-related problems."[212]

This decision approves SCE's forecast of GHG costs and allocation of GHG allowance proceeds to maintain a key aspect of the GHG reduction program envisioned by AB 32 and Pub. Util. Code Section 748.5 and, as a result, will improve the health and safety of California residents.

12. Compliance with the Authority Granted Herein

SCE is authorized to update the final 2022 year-end balances with recorded actuals through December 2022. SCE must submit a Tier 1 Advice Letter to the Commission's Energy Division within 30 days of the date of issuance of this decision in order to implement the rate changes authorized by this decision. The

[212] AB 32 § 38501(a).

tariff sheets filed in this Advice Letter shall be effective on or after the date filed, subject to the Commission's Energy Division determining that SCE's Advice Letter complies with this decision.

SCE is authorized to implement the revenue requirement adopted in this proceeding, and as updated to reflect 2022 year-end actuals, in its proposed rate change on January 1, 2023.

13. Reduction of Comment Period and Party Comments

The proposed decision of ALJ Shannon O'Rourke in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3. Pursuant to Rule 14.6(b), all parties stipulated to reduce the 30-day public review and comment period required by Pub. Util. Code Section 311 to 11 days for opening comments and seven days for reply comments.

Comments were filed on ________________, and reply comments were filed on ________________ by ________________.

14. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Shannon O'Rourke is the assigned ALJ in this proceeding.

Findings of Fact

<u>2022 Forecast Overview and Methodology</u>

1. SCE's total forecast ERRA revenue requirement for 2023 is $5,242.224 million.

2. SCE forecasts an increase in total retail electricity sales from a forecast 85,156 GWh in 2022 to a forecast 85,327 GWh in 2023.

3. SCE forecasts an increase of 0.6% in total electric customers from 5,200,618 in 2022 to 5,230,870 in 2023.

4. SCE's preliminary forecast includes the statewide increase in the DA load expected to start in 2021 and CCAs that meet the following criteria: (1) filed a binding notice of intent to begin CCA service; (2) filed an initial RA filing; (3) started CCA service; and (4) formally submitted an April RA forecast pursuant to Pub. Util. Code Section 380.

<u>SCE's Portfolio of Resources</u>

5. SCE's UOG and Purchased Power contracts in 2023 consist of 1,176 MW nameplate capacity of hydroelectric power, 91 MW of solar photovoltaic resources, 10,205 MW of CHP and renewables projects resources, and 245 MW of natural gas resources.

6. SCE executed two inter-utility contracts for 2023, consisting of: (1) an entitlement of 280.245 MW of contingent capacity and 238.16 GWh of firm energy through a contract with WAPA; and (2) 3 MW of energy from the Azusa Powerhouse through a corporate grant deed.

7. SCE forecast F&PP costs associated with six types of contracts for new generation resources in 2023, including: (1) New System Generation CAM contracts; (2) System Reliability Modified CAM contracts; (3) Emergency Reliability contracts; (4) Mid-Term Reliability contracts; (5) Generic and Bilateral contracts used to meet 2023 system capacity requirements; and (6) Contracts used to meet local capacity requirements.

8. SCE's procurement-related Public Purpose Program Charge funds: (1) behind the meter resources procured through the PRP #2; (2) net costs associated with biomass generation associated with the Tree Mortality Non-Bypassable Charge; (3) net charges for the BioMAT program; and (4) volumetric electricity service subsidies through the DAC-GT and CSGT programs.

9. SCE forecasts 165,427,386 kWh of participation through the Green Tariff Shared Renewables program in 2023.

10. SCE forecasts $4.7 million in interim spent nuclear fuel costs at SONGS in 2023.

11. SCE forecasts $29.8 million in costs for nuclear fuel expenses and $0.0 million net interim spent nuclear fuel expenses at PVNGS in 2023.

12. SCE forecasts a cost of $9.482 million to provide electricity service to Catalina Island, which includes the $8.976 million in diesel fuel and $0.505 million for propane in 2023.

13. SCE forecasts costs for 6 GWh of energy reductions in 2023 to provide economic demand response programs, including the Summer Discount Plan, Capacity Bidding Program, Critical Peak Pricing, and Smart Energy Programs.

14. SCE forecasts F&PP costs in 2023 associated with the net CAISO costs of grid management charges, Federal Energy Regulatory Commission fees, congestion fees, Congestion Revenue Rights actions-related CAISO costs, ancillary services, CAISO uplift costs, Standard Capacity Product costs, and other non-energy related CAISO costs.

15. SCE forecasts 2023 hedging costs for energy-related transaction fees and option premiums for hedging SCE's open energy position in workpapers for 2023.

16. SCE forecasts $4.433 million in 2023 costs associated with natural gas delivery to SCE's UOG fuel cells at UC Santa Barbara and California State University at San Bernardino, Mountainview Generating Station, and a daily reservation charge of for Backbone Transportation Service.

17. SCE has a $3.350 billion multi-year revolving credit facility, also called the "revolver," to serve short-term borrowing requirements.

18. SCE forecasts costs associated with the revolving credit facility in workpapers for 2023, including: (1) $20,000 administrative fee; (2) 17.5 basis point annual facility fee; (3) 107.5 basis point participation fee on any outstanding letters of credit; (4) 20 basis point issuer fee on any letters of credit; and (5) Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points borrowing (loan) rate.

19. SCE forecasts fuel inventory carrying costs for nuclear, natural gas, and diesel in workpapers for 2023.

20. SCE forecasts GHG procurement compliance carrying costs for 2023, which SCE estimates using historical GHG inventory balances and the ERRA BA interest rates in workpapers for 2023.

21. SCE forecasts the carrying costs associated with SCE's collateral requirements necessary to procure power in workpapers for 2023.

SCE's Revenue Requirement and Ratemaking Proposal

22. SCE's 2023 forecast bundled service customer rates are as follows:

Rate Schedule by Customer Group	**Total Delivery** (¢/kWh)	**Total Generation** (¢/kWh)	**Total** (¢/kWh)	**% Change from 10/1/2021**
Domestic				
• D	16.964	14.534	31.499	2.9%
• D-CARE	5.237	14.536	19.733	2.0%
• D-APS	15.726	14.545	30.271	5.0%
• DE	9.353	14.528	23.880	4.3%
• DM	4.824	14.576	19.399	-41.7%
• DMS-1	17.374	14.576	31.950	-3.1%
• DMS-2	17.300	14.575	31.875	1.3%

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	% Change from 10/1/2021
Lighting-Small, Med. Power				
• GS-1	12.706	13.997	26.702	4.8%
• GS-2	15.329	12.544	27.873	3.1%
• TC-1	18.412	11.363	29.775	-0.5%
• TOU-GS	13.017	11.542	24.559	3.8%
Large Power				
• TOU-S	10.792	10.722	21.514	5.2%
• TOU-P	9.606	10.271	19.876	4.5%
• TOU-T	3.576	9.501	13.076	11.8%
• TOU-8-S-S	11.442	11.437	22.879	9.1%
• TOU-8-S-P	11.501	10.847	22.348	9.0%
• TOU-8-S-T	4.634	9.784	14.419	14.4%
Agricultural & Pumping				
• TOU-PA-2	13.241	12.176	25.417	9.6%
• TOU-PA-3	9.857	9.974	19.831	3.9%
Street & Area Lighting				
• LS-1	45.286	7.766	53.052	0.4%
• LS-2	15.725	7.7759	23.484	0.9%
• LS-3	7.491	7.774	15.266	6.0%
• DTL	35.490	7.766	43.256	0.4%
• OL-1	29.430	7.766	37.196	0.5%
Average Rate — All Groups	12.020	12.424	24.444	2.9%

23. SCE's 2023 forecast Generation Service revenue requirement is $5,671.042 million, which will be allocated in balancing accounts as follows:

Description	SCE Proposed 2023 Revenue Requirement (millions)
2023 F&PP Costs (including GHG costs)	
• ERRA BA-related	$5,067.457
• PABA-related	-$81.655
• Green Tariff Shared Renewables BA-related	$9.814

Description	SCE Proposed 2023 Revenue Requirement (millions)
2022 ERRA BA True-up	$835.092
2022 PABA True-Up	-$158.105
2022 Energy Settlement MA True-Up	-$1.560
Total Generation Service	**$5,671.042**

24. The Green Tariff Shared Renewables BA forecast amount of $9.814 million is accurate.

25. In total, SCE has an overcollection of $1.560 million in the Energy Settlement MA and Litigation Costs TA.

26. SCE's 2023 forecast Delivery Service revenue requirement is negative $428.820 million, which will be allocated as follows:

Description	SCE Proposed 2023 Revenue Requirement (millions)
New System Generation • New System Generation F&PP 2023 Forecast[213] and 2023 System Reliability F&PP • New System Generation BA 2022 True-Up	 $282.419 $97.951
Spent Nuclear Fuel	$4.740
Distribution Rate Component • Base Revenue Requirement BA-Distribution F&PP 2023 Forecast • GHG Allowance Revenues 2023 Forecast	 -$11.473 -$773.198

[213] Estimate includes indirect GHG costs.

Description	SCE Proposed 2023 Revenue Requirement (millions)
Public Purpose Programs Charge • Public Purpose Program F&PP Charge 2023 Forecast • Tree Mortality Non-Bypassable Charge BA 2022 True-Up • BioMAT Non-Bypassable Charge BA 2022 True-Up	 $14.100 -$38.634 -$4.725
Total Delivery Service	**-$428.820**

GHG Forecast Costs, Revenues and Reconciliation

27. SCE forecast its 2023 GHG allowance revenue using a forecast proxy price of $30.26/MT.

28. SCE was allocated 24,357,709 allowances by CARB for 2023.

29. SCE's net forecast revenue proceeds from GHG allowances granted by CARB in 2023 is $827.705 million, which includes an $8.244 million refund in 2023 for FF&U, and a refund of $82.397 million from an overcollection in the GHG Revenue BA in 2022.

30. SCE's 2023 forecast administrative and customer outreach expenses to be set aside is $328,635 including FF&U.

31. SCE anticipates the IOUs' combined allocation of forecast GHG allowance revenues for 2023 would exceed $1 billion.

32. SCE erred in calculating its net GHG allowance revenue total by calculating the SOMAH funding true-up as a credit instead of a debit.

33. The correct SOMAH funding true up is $2.183 million in GHG allowance revenue to be set aside for the net true-up of the program.

34. SCE's GHG allowance revenue to be set aside for SOMAH program funding in 2023 is $46.528 million.

35. SCE does not require GHG allowance revenue in 2023 for its DAC-GT and CSGT programs because it has sufficient funds set aside to cover forecast costs.

36. CPA's total 2023 program forecast for its DAC-GT and CSGT programs includes a net allocation of $0.313 million from GHG allowance revenue in 2023 and $2.281 million from Public Purpose Program funding in 2023.

37. Joint CCAs' total 2023 program forecast for its DAC-GT and CSGT programs includes a net allocation of $0.154 million from GHG allowance revenue in 2023 and $0.625 million from Public Purpose Program funding in 2023.

38. SCE requests $0.4 million from GHG allowance proceeds to implement the CEOP in 2023.

39. SCE's 2023 forecast EITE customer return is $40.416 million.

40. SCE's 2023 forecast semi-annual California Climate Credit is $71 per eligible residential and small commercial account, based on a forecast of 5,160,130 eligible recipients.

<u>Cost Responsibility Surcharges</u>

41. For 2023, CTC costs are as follows: (1) $0.00007/kWh for Domestic (D) customers of all vintages; (2) $0.00006/kWh for St. Lighting customers of all vintages; (3) $0.00005/kWh for TOU-GS-1, TC-1, TOU-GS-2, TOU-GS-2, TOU-8-Sec, TOU-8-Pri, TOU-PA-2, TOU-PA-3, Standby-Sec, Standby-Pri customers of all vintages; and (4) $0.0004/kWh for TOU-8-Sub and Standby-Sub customers of all vintages.

42. For 2023, the SCE Wildfire Non-Bypassable Charge is $0.00652/kWh for all customer classes in all vintages.

43. SCE erred in calculating two values that impact its RA value, which, when corrected, result in a net decrease to the 2023 Indifference Amount of $22.669 million (without Uncollectibles) compared to SCE's original calculation.

44. SCE's corrected forecast 2023 PCIA revenue requirement is as follows:

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	$4,132.129
Market Value	$4,617.935
• Energy Value	$3,417.991
• RPS Value	$353.036
• RA Value	$846.908
One-Time Adjustments	-$1.543
Total 2023 Indifference Amount	-$485.806
Balancing Account True-Ups (no Uncollectibles Factor)	
• 2022 YE PABA Balance	-$156.357[214]
• 2022 GRC Memo Account (27-Month Amortization)	-$3.525
• 2022 YE ERRA Balance	$825.855[215]
2023 PCIA Revenue Requirement	$178.625
2023 PCIA Revenue Requirement with Uncollectibles Factor	$178.947

45. SCE's corrected 2023 PCIA rates are as follows:

PCIA Vintage Year	2023 PCIA Rates, System Average ($/kWh)
2001	-0.00003
2004	-0.00003

214 -$156.639 million with the Uncollectibles Factor.

215 $827.344 million with the Uncollectibles Factor.

PCIA Vintage Year	2023 PCIA Rates, System Average ($/kWh)
2009	0.00028
2010	0.00027
2011	0.00056
2012	0.00051
2013	0.00002
2014	-0.00267
2015	-0.00625
2016	-0.00663
2017	-0.00772
2018	-0.00679
2019	-0.01116
2020	-0.01001
2021	-0.01062
2022	0.00750
2023	0.00566

46. SCE's current approach to collecting franchise fees from departing load customers results in an overcharge.

<u>ERRA Trigger Mechanism Application</u>

47. SCE's ERRA balance of $245.694 million exceeded the 4% ERRA trigger point of $202.471 million in August 2022.

48. SCE's ERRA balance was not expected to self-correct below the AB 57 threshold of $253.088 million within 120 days of SCE's trigger point exceedance.

49. SCE filed a trigger application within 30 days of exceeding its ERRA trigger point.

50. The primary driver of the undercollection resulting in SCE's trigger threshold exceedance was higher-than-expected market power prices, which resulted in a 19% increase in recorded costs in the ERRA BA.

Other

51. Challenges to facts supporting SCE's proposed 2023 forecast of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and year-end balancing accounts are waived by parties in this proceeding by virtue of stipulation to waive evidentiary hearing.

Conclusions of Law

1. SCE's forecast, as modified in this decision, of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and year-end balancing account balances are reasonable.

2. SCE's proposed cost responsibility surcharges, as modified in this decision, are reasonable.

3. SCE complied with the Commission's expedited ERRA trigger mechanism requirements as set in D.02-10-062, D.04-12-048, D.06-06-051, D.19-12-001, and D.22-08-023.

4. All 2022 year-end balances should be updated using recorded actuals through December 2022.

5. SCE should be allowed to implement the revenue requirement adopted herein, as updated with 2022 year-end actuals, on January 1, 2023.

6. SCE should update its Preliminary Statement WW to cease gross-up of the PCIA revenue requirement with the Franchise Fee Factor.

7. Advice Letters to implement changed tariff sheets in accordance with this Decision should be filed as Tier 1 Advice Letters.

8. All rulings issued by the assigned Commissioner and the assigned ALJ should be confirmed.

9. All motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, should be denied.

10. Consolidated applications A.22-05-014 and A.22-09-017 should be closed.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is authorized to recover a total 2023 Energy Resource Recovery Account electric procurement cost revenue requirement forecast of $5,242.224 million, consisting of both a generation service component and a delivery service component.

2. Within Southern California Edison Company's (SCE) generation service revenue requirement of $5,671.042 million, SCE is authorized to recover a total of $4,995.620 million in fuel and purchased power costs and transfer the following account balances: (1) $835.092 million from the Energy Resource Recovery Account (ERRA) Balancing Account (BA); (2) -$158.105 million from the Portfolio Allocation BA; and (3) -$1.560 million from the Energy Settlement Memorandum Account.

3. Within Southern California Edison Company's (SCE) delivery service revenue requirement of negative $428.820 million, SCE is authorized to recover the following: (1) $282.419 million for the New System Generation and System Reliability fuel and purchase power contracts; (2) $4.740 million in spent nuclear fuel costs; (3) -$11.473 million for forecast Base Revenue Requirement Balancing Account — Distribution fuel and purchased power costs; (4) -$773.198 million

customer return of greenhouse gas allowance proceeds; and (5) $14.100 million for the Public Purpose Program Charge, which includes the Tree-Mortality Non-Bypassable Charge, SCE's Preferred Resources Pilot #2, Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge, and a portion of the Disadvantaged Communities — Green Tariff and Community Solar Green Tariff program funding which provides volumetric subsidies to qualifying customer classes. SCE is also authorized to transfer the following account balances: (1) $97.951 million 2022 year-end balance in the New System Generation Balancing Account (BA); (2) -$38.634 million in the 2022 year-end balance for the Tree Mortality Non-Bypassable Charge BA; and (3) -$4.725 million in the 2022 year-end BioMAT Non-Bypassable Charge BA.

4. Southern California Edison Company (SCE) is authorized to reconcile greenhouse gas (GHG) costs, revenues and requirements as follows: (1) recover a revenue requirement of $452.317 million in GHG Cap-and-Trade costs; and (2) distribute $773.198 million in forecast 2023 GHG allowance auction proceeds to its customers ($827.705 million net auction proceeds, which includes a $82.397 million overcollection in GHG auction revenue during 2022, $737.064 million in forecast GHG allowance revenue in 2023, and $8.244 million forecast refund from Franchise Fees and Uncollectibles during 2023), with $54.178 million set aside for clean energy and energy efficiency projects, and $0.330 million set aside for outreach and administrative expenses.

5. Southern California Edison Company (SCE) must return $773.198 million in net greenhouse gas allowance proceeds to SCE's customers in 2023.

6. Southern California Edison Company is authorized to return $40.416 million to its Emissions-Intensive and Trade-Exposed customers in 2023.

7. The forecast amount of $71 semi-annually per residential household or small business for the California Climate Credit program is authorized to be returned in 2023.

8. Southern California Edison Company shall file a Tier 1 Advice Letter and revised tariff sheets within 30 days of the issuance of this decision to implement this decision. The Advice Letter shall include changed tariff sheets and supporting documentation for:

(a) Residential rate schedules (including master-metered rate schedules) to include the authorized 2023 Climate Credit amount;

(b) Small business rate schedules to include the authorized 2023 Climate Credit amount;

(c) The amount approved in Ordering Paragraph 1, as updated to reflect 2022 year-end actuals; and

(d) The removal of the Franchise Fee Factor from the gross-up of the Power Charge Indifference Adjustment revenue requirement.

9. Southern California Edison Company's request to keep its rates unchanged as a result of the Energy Resource Recovery Account trigger application is granted.

10. Southern California Edison Company must implement the revenue requirement adopted herein, as updated with 2022 year-end actuals, on January 1, 2023.

11. All rulings issued by the assigned Commissioner and Administrative Law Judge (ALJ) are affirmed herein; and all motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, are denied.

12. Consolidated Application (A.) 22-05-014 and A.22-09-017 are closed.

This order is effective today.

Dated ________________________, at San Francisco, California.

APPENDIX A

Acronym List

APPENDIX A

Acronym List

ACRONYM	DESCRIPTION
AB	Assembly Bill
AL	Advice Letter
ALJ	Administrative Law Judge
BA	Balancing Account
BioMAT	Bioenergy Market Adjusting Tariff
CAISO	California Independent System Operator
Cal Advocates	The Public Advocates Office of the Public Utilities Commission
CAM	Cost-Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CDWR	California Department of Water and Resources
CEOP	Clean Energy Optimization Pilot
CHP	Combined Heat and Power
CPA	Clean Power Alliance of Southern California
CPE	Central Procurement Entity
CSGT	Community Solar Green Tariff
CTC	Competition Transition Charge
D	Domestic Service
DA	Direct Access
DACC	Direct Access Customer Coalition
DAC-GT	Disadvantaged Communities — Green Tariff
DAC-SASH	Disadvantaged Communities — Single-family Solar Homes
D-APS	Domestic Automatic Powershift Withdrawn 2809-E 12/9/12
D-CARE	Domestic Service — California Alternate Rates for Energy

ACRONYM	DESCRIPTION
DE	Domestic Service to Utility Employees
DM	Domestic Service Multifamily Accommodation
DMS -1	Domestic Service, Multifamily Accommodation – Submetered
DMS -2	Domestic Service, Mobilehome Park Multifamily Accommodation, Submetered
DWL	Residential Walkway Lighting
DWRBC	Department of Water Resources Bond Charge
ECAC	Energy Cost Adjustment Clause
EITE	Emissions-Intensive and Trade-Exposed
ERRA	Energy Resource Recovery Account
F&PP	Fuel and Purchased Power
FF&U	Franchise Fees and Uncollectibles
GHG	Greenhouse Gas
GRC	General Rate Case
GS-1	General Service 1
GS-2	General Service 2
GW	Gigawatt
GWh	Gigawatt Hours
Joint CCAs	CalChoice, Lancaster Energy Pico Rivera Innovative Municipal Energy, and San Jacinto Power
kWh	Kilowatt Hour
LS-1	Lighting — Street and Highway 1
LS-2	Lighting — Street and Highway 2
LS-3	Lighting — Street and Highway 3
MA	Memorandum Account
MT	Metric Ton
MW	Megawatt

ACRONYM	DESCRIPTION
MWh	Megawatt Hours
OL-1	Outdoor Lighting 1
OP	Ordering Paragraph
PABA	Portfolio Allocation Balancing Account
PCIA	Power Charge Indifference Adjustment
PHC	Pre-Hearing Conference
PPA	Power Purchase Agreement
PRP	Preferred Resources Pilot
PVNGS	Palo Verde Nuclear Generating Station
PUBA	Portfolio Allocation Balancing Account Undercollection Balancing Account
PY	Planning Year
RA	Resource Adequacy
RPS	Renewables Portfolio Standard
SCE	Southern California Edison Company
SoCal CCAs	Clean Power Alliance of Southern California, California Choice Energy Authority and Central Coast Community Energy
SOMAH	Solar on Multifamily Affordable Housing
SONGS	San Onofre Generating Station
SP15	South of Path 15
TA	Tracking Account
TC-1	Traffic Control 1
TOU-8-P	Time-of-Use, General Service — Primary Distribution
TOU-8-S	Time-of-Use, General Service — Large Standby
TOU-8-S-P	Time-of-Use, General Service — Large Standby — Primary Distribution

ACRONYM	DESCRIPTION
TOU-8-S-S	Time-of-Use, General Service — Large Standby — Secondary Distribution
TOU-8-S-T	Time-of-Use, General Service — Large — Standby – Tiered
TOU-8-T	Time-of-Use, General Service — Large — Tiered
TOU-GS	Time-of-Use General Service
TOU-PA-2	Time-of-Use Agricultural & Pumping 2
TOU-PA-3	Time-of-Use Agricultural & Pumping 3
UOG	Utility-Owned Generation
WAPA	Western Area Power Administration

(END OF APPENDIX A)