ALJ/CS8/mph **Date of Issuance 12/1/2023**

Decision 23-11-094 November 30, 2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U 338-E) For Approval of Its 2024 ERRA Forecast Proceeding Revenue Requirement.	Application 23-06-001

SOUTHERN CALIFORNIA EDISON COMPANY'S 2024 ENERGY RESOURCE RECOVERY ACCOUNT FORECAST

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SOUTHERN CALIFORNIA EDISON COMPANY'S 2024 ENERGY RESOURCE RECOVERY ACCOUNT FORECAST

Summary

This Decision approves, with modifications, Southern California Edison Company's (SCE) 2024 Energy Resource Recovery Account (ERRA) Forecast and approves a 2024 forecast revenue requirement of $5.234 billion, representing a decrease of $325.830 million as compared to rates effective today.

SCE's proposed revenue requirement consisted 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, 2024, SCE's system average rates for bundled customers will decrease by 1.8 percent as compared to rates effective October 1, 2023, to 26.124¢/kilowatt hour in 2024. The Power Charge Indifference Adjustment (PCIA) rates will be negative for most customer vintages and will be negative system-wide in 2024, resulting in credits for customers in most PCIA vintages.

SCE's proposed 2024 generation service revenue requirement, as updated October 13, 2023, and in SCE's Errata filed on October 24, October 27, and October 31, 2023, totaled $5.513 billion, reflecting a reduction of approximately $567.21 million, or 9.3 percent, from what is currently recovered in generation service rates. This Decision authorizes SCE to transfer the following account balances related to its generation service rates: -$800.09 million from the 2023 ERRA Balancing Account (BA), $523.664 million from the 2023 Portfolio Allocation Balancing Account (PABA), and $1,126 million from the 2023 Energy Settlement Memorandum Account (ESMA).

Within SCE's forecasted 2024 delivery service revenue requirement of negative $279.280 million, SCE is authorized to recover the following:

(1) $402.996 million for New System Generation (NSG) and System Reliability fuel and purchase power contracts; (2) $4.958 million in spent nuclear fuel costs; (3) -$3.582 million for forecast Base Revenue Requirement Balancing Account — Distribution fuel and purchased power costs; (4) -$955.105 million customer return of greenhouse gas (GHG) allowance proceeds; and (5) $13.056 million for the Public Purpose Program Charge, which includes the Tree-Mortality Non-Bypassable Charge (TMNBC), 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 delivery-service related account balances: (1) $256.10 million in the 2023 year-end balance in the New System Generation BA; (2) $10.588 million in the 2023 year-end balance for the Tree Mortality Non-Bypassable Charge BA; and (3) -$6.689 million in the 2023 year-end BioMAT Non-Bypassable Charge (BMNBC) BA.

This Decision approves SCE's 2024 forecasted semi-annual California Climate Credit for residential and small business customers of $86.00 per eligible account and authorizes SCE to return up to $58.834 million to emissions-intensive trade-exposed (EITE) customers.

SCE's procurement-related revenue requirement will be updated to reflect 2023 year-end balances with recorded actuals through November 2023 and forecast for December 2023. SCE will implement the rate changes on January 1, 2024, in the Tier 1 Advice Letter filed in conformance with this Decision.

A summary of SCE's 2024 ERRA Forecast Revenue Requirement Changes is provided below:

Table – SCE 2024 ERRA Forecast Revenue Requirement Changes ($000)[1]

	October Update	In Rates[2]	Revenue Requirement Change
2024 Forecast Fuel and Purchased Power[3]	5,1118,545	5,291,795	(173,250)
2023 Year End (YE) ERRA BA	207,835	1,007,926	(800,091)
2023 YE ESMA – Net Amount[4]	(380)	(1,506)	1,126
2023 YE PABA	601,728	78,064	523,664
2023 YE NSGBA	256,095	4,417	251,678
2023 YE MCAMBA[5]	990	-	990
2023 YE TMNBCBA	10,588	(41,675)	52,263
2023 YE BMNBCBA	(6,689)	(6,387)	(302)
GHG Allowance Revenues	(955,105)	(733,198)	(221,907)
Total ERRA Revenue Requirement	**5,233,606**	**5,559,437**	**(325,830)**

Finally, this Decision defers (1) consideration of fixed generation cost issues raised in this and other investor-owned utility 2024 ERRA Forecast Proceedings to a future Commission action, and (2) denies reconsideration of issues associated with the valuation of banked Renewable Energy Certificates

[1] Exhibit SCE-06E3 at 9.

[2] The 2023 ERRA Forecast revenue requirement was authorized in D.22-12-012 and implemented in rates on January 1, 2023 via Advice Letter 4919-E.

[3] Includes spent nuclear fuel.

[4] Reflects 12/31/2023 forecasted ESMA refunds with a deduction for forecast litigation-related costs.

[5] Reflects three-year amortization adjustment pursuant to Resolution E-5240.

that were addressed in prior Decisions (D.)23-06-006 and D.19-10-001. Application 23-06-001 remains open solely to address fixed generation cost issues, pursuant to an Administrative Law Judge ruling issued on October 9, 2023.

1. Procedural Background

SCE filed its 2024 Energy Resource Recovery Account (ERRA) Forecast Application (A.) 23-06-001 on June 1, 2023, seeking approval of a $4.932 billion proceeding revenue requirement. According to SCE, its forecast reflected a decrease of approximately $627 million relative to its revenue requirement being recovered in rates in 2023.[6] On October 13, 2023, SCE updated its 2024 ERRA forecasted revenue requirement to $5.234 billion, reflecting a decrease in rates of $325.830 million compared to rates in effect on October 1, 2023.[7]

Pursuant to D.14-10-003, SCE also proposed to return a total of approximately $955.105 million in net greenhouse gas (GHG) allowance revenues to eligible customers, which would provide residential and small commercial customers a semi-annual on-bill California Climate Credit of approximately $86.00 per customer in 2024, once in April and once in October.

On July 6, 2023, the California Community Choice Association (CalCCA) and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed protests to SCE's Application. Also on July 6, 2023, the Direct Access Customer Coalition (DACC) filed a response to the Application. On July 17, 2023, SCE filed a reply to the parties' protests and response. CalCCA,

[6] Exhibit SCE-01C at 1-2. The rates effective in 2023 were adopted in D.22-12-012.

[7] SCE filed errata to its October Update on October 24, October 26, and October 31, 2023, 2023. Its initial October Update, SCE forecasted a revenue requirement of $5.236 billion, which would have been a decrease of $303.467 million compared to rates in effect as of October 1, 2023.

Cal Advocates, and DACC were granted party status given their timely response to SCE's Application.

A prehearing conference (PHC) was held on July 21, 2023, to discuss the issues of law and fact and determine the need for hearing and schedule for resolving the matter. No other parties requested party status in this proceeding during the PHC.

On August 1, 2023, the assigned Administrative Law Judge (ALJ) issued a Ruling Directing Parties to Comment Regarding Fixed Generation Costs (Ruling), specifically seeking feedback on issues related to the categories of fixed generation costs included in SCE's ERRA forecast, and requesting party comment on whether issues related to fixed generation costs should be addressed in the instant proceeding.

On August 3, 2023, Assigned Commissioner John Reynolds issued the Scoping Memo and Ruling.

On August 15, 2023, SCE filed additional supplemental testimony pursuant to D.23-06-006, which directed the investor-owned utilities to use an updated methodology to forecast the Energy Index Market Based Price (Energy Index MBP) used to set the Power Charge Indifference Adjustment (PCIA).[8]

Opening comments on the Ruling were filed and served on August 16, 2023, by SCE, CalCCA, and Cal Advocates. Reply comments were

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[8] The Commission adopted the PCIA to ensure that when electric customers of an investor-owned utility (utility or IOU) depart from utility service and receive their electricity from a non-utility provider, those customers remain responsible for costs previously incurred on their behalf by the utilities. D.23-06-006 updated the cost methodology to reflect three full years of historical data to modify the Energy Index MBP applied to their PCIA-eligible energy resource portfolios and directed SCE to update its 2024 ERRA Forecast Application workpapers to reflect whether it elects to provide an interim allocation of large hydroelectric resources. *See* D.23-06-006 at Ordering Paragraph 3 and Appendices A-B.

filed and served on August 23, 2023, by SCE, CalCCA, and DACC. Because the Ruling was simultaneously filed in the ongoing ERRA proceedings for Pacific Gas and Electric Company (PG&E; A. 23-05-012) and San Diego Gas & Electric Company (SDG&E; A.23-05-013), SCE requested the party comments filed and served in those two proceedings also be recognized in this proceeding.[9] The three ERRA forecast proceedings are not consolidated at this time.

On August 28, 2023, intervenor testimony was filed by CalCCA.

SCE filed rebuttal testimony on September 12, 2023. A joint case management statement was filed on September 15, 2023, stating that two parties indicated that evidentiary hearings in this proceeding were necessary. On September 18, 2023, the ALJ issued a ruling requesting the parties identify specific disputed factual issues and complete a template providing the evidence to be considered during evidentiary hearings. On September 20, 2023, DACC filed a notice to the A.23-06-001 service list that it would not participate in any evidentiary hearings in this proceeding due to its lack of a non-disclosure agreement with SCE.

On September 21, 2023, CalCCA filed a notice to the A.23-06-001 service list explaining that it and SCE had reached a stipulation and that no evidentiary hearing would be necessary on the banked REC issues previously identified in this proceeding.

In a ruling issued on September 22, 2023, the ALJ removed evidentiary hearing from the schedule and directed SCE and CalCCA to file the stipulated joint motions no later than September 26, 2023.

[9] SCE reply comments to the Ruling at 1-2.

The same ruling modified the procedural schedule to change the deadline for the issuance of the Proposed Decision (PD) to account for the Veteran's Day Holiday, and further modified the deadline for comments and reply comments to the PD.

On September 26, 2023, CalCCA filed three additional proposed exhibits.

On October 9, 2023, the ALJ issued a ruling stating that the fixed generation cost issues raised in the Ruling would be addressed in a separate Track 2 of this proceeding. Because the fixed generation costs are not being considered in Track 1 of this proceeding, we are not incorporating opening or reply comments filed in PG&E or SDG&E's 2024 ERRA forecast proceedings addressing the Ruling into the record of Track 1 of A.23-06-001.

On October 13, 2023, SCE filed its October Update providing the updated workpapers and calculations for its 2024 ERRA forecast based on recent months' actual data. SCE's updated requested revenue requirement sought authorization to recover $5.234 billion in rates in 2024.[10] The change in revenue requirement in SCE's October Update was based on:

1. Four percent higher gas prices and six percent lower power prices in 2024;
2. A lower 2024 SP-15 power price forecast resulting in decreasing forecasted load procurement costs;
3. Higher costs associated with:
    a. Summer reliability and 2021 midterm reliability (MTR) projects,
    b. Gas transportation agreements,
    c. Exercise of put options, and

[10] SCE's initial October Update forecasted a revenue requirement of $5.236 billion, but three errata amended its forecast to $5.234 billion to reflect the Departing Load customers now represented by the City of Huntington Beach.

d. The inclusion of SCE utility-owned storage facilities.

4. Decreased costs due to changes in online dates for SCE's MTR portfolio;
5. Higher sales revenues for forecasted Resource Adequacy and Voluntary Allocation sales, due to a higher Commission-issued 2024 Forecast market price benchmark (MPB); and
6. Higher contracted prices paid in SCE's Long-Term Market Offer process than the Renewable Energy Credit (REC) MPB used in SCE's June Testimony.[11]

SCE's October Update also proposed to return $955.105 million in net GHG allowance revenues to eligible customers in 2024, based on the Commission's adopted methodologies and updated GHG revenues and California GHG Cap-and-Trade costs, increasing the residential and small commercial customers' semi-annual, on-bill California Climate Credit from $58.00 to $86.00 in 2024. [12]

On October 24 and 26, 2023, SCE filed errata to its October 13, 2023, Update testimony and workpapers.

On October 27, 2023, SCE, DACC, and CalCCA filed opening comments on SCE's October Update and associated errata, as well as concurrent opening briefs.

SCE filed a final errata to its October Update testimony and workpapers on October 31, 2023. Reply comments to SCE's October Update, associated errata, and opening briefs were filed on November 2, 2023, by CalCCA and SCE.

On October 27, 2023, CalCCA and SCE filed separate motions to admit exhibits to the evidentiary record of this proceeding.

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[11] Exhibit SCE-06C at 6-14.

[12] Exhibit SCE-06C at 1.

On November 7, 2023, the ALJ issued a ruling accepting testimony and additional documentation as exhibits into evidence in this proceeding.

2. Jurisdiction

The Commission oversees ERRA proceedings to determine what fuel and purchased power costs investor-owned electric utilities, such as SCE, can recover in rates. A.23-06-001 is an annual ERRA forecast proceeding, which is intended to evaluate the utility's electric procurement cost revenue requirements for the following year, in this instance, 2024. The ERRA process was established in California Public Utilities Code (Pub. Util. Code) § 454.5(d), Rules 2.1 and 3.2 of the Commission's Rules of Practice and Procedure, and D.02-10-062.[13]

3. Issues Before the Commission

The issues to be determined or otherwise considered are as follows:

1. Whether SCE's requested 2024 ERRA forecast revenue requirement of $5.234 billion is reasonable, including but not limited to consideration of the following:[14]
    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

[13] All references to code herein refer to the California Public Utilities Code (Pub. Util. Code).

[14] A.23-06-001 initially requested $4.932 million, which was updated in SCE's October Update and associated errata to $5.234 billion.

Non-Bypasssable Charge BA, 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 Power Charge Indifference Adjustment (PCIA) and Competitive Transmission Charge are reasonable, including discussion of the following:
    a. Treatment of Resource Adequacy resources and associated costs in the PCIA;
    b. Treatment of Renewables 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 SCE's request and methods used to determine the issues described above comply with all applicable rules, regulations, resolutions, and Decisions for all customer categories.
8. Whether there are any safety concerns.

As noted in Section 1, above, an ALJ Ruling issued October 9, 2023, deferred consideration of fixed cost generation issues raised in the Ruling to a second track of A.23-06-001.

4. 2024 Forecast Overview and Methodology

SCE forecasted 2024 revenue requirement based on modeling of total electricity sales and customers for its service territory that was completed in December 2022, adjusted to account for the bundled customer portion of load. SCE proposed to include the following forecast year-end 2023 balancing and memorandum account balances in the 2024 ERRA Forecast revenue requirement: ERRA BA, Energy Settlements Memorandum Account (ESMA)/Litigation Costs Tracking Account (LCTA), New System Generation Balancing Account (NSGBA), Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA), BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA), Portfolio Allocation Balancing Account (PABA), and the Modified Cost Allocation Mechanism Balancing Account (MCAMBA), pursuant to D.15-10-037, D.18-12-003 and D.18-10-019.[15]

SCE's forecasted 2024 fuel and power purchase (F&PP) costs are associated with its utility-owned generation (UOG) resources, purchased power contracts, financing, various carrying costs, and procurement contracts to meet reliability requirements set by the Commission. In its October Update, as updated in its October 24, 26, and October 31, 2023, errata, SCE forecasted its 2024 total forecasted F&PP revenue requirement to be lower than SCE's 2023 ERRA forecast when accounting for:

1. Updating SCE's bundled service customer load forecast for net energy metering (NEM) adjustments, which is 1.4

[15] Exhibit SCE-01C at 1.

percent lower in 2024 when compared to the gross bundled load used in 2023;

2. Increased revenue from Resource Adequacy (RA) and Renewable Energy Certificate (REC) sales, including Voluntary Allocation, due to the higher 2024 Market Price Benchmark (MPB);
3. Higher sales revenue from the Market Offer process due to a higher contractual price in 2024 relative to the 2023 MPB; and
4. Contract terminations of a large portion of SCE's gas dispatchable portfolio.

The adjusted, and lower, F&PP revenue requirement reflects increased costs associated with:

1. Hedging costs associated with SCE's loss of energy rights for the local capacity requirement (LCR) dispatchable units;
2. A forecast of 22 percent higher gas prices and 17 percent lower power prices in 2024; and
3. The addition of new RA purchases, including contracts related to MTR procurement.

In its October Update, SCE requested a 2024 ERRA Forecast proceeding revenue requirement of $5.234 billion, beginning in 2024, which represents a decrease of approximately $325.830 million from the ERRA Forecast-related revenue requirement currently reflected in customers' 2023 ERRA Forecast-related rates.[16] These costs are described in more detail in Section 5, below.

SCE noted that its F&PP expenses, for the purposes of setting its 2024 rates, also reflect the costs of implementing its second Risk Assessment Management

[16] Exhibit SCE-06C at 6, as updated by SCE's Errata to SCE-06C filed October 24, 26, and October 31, 2023.

Phase (RAMP), which it filed on May 13, 2022. The RAMP is intended to provide Commission staff and interested parties the opportunity to analyze the models SCE uses to evaluate safety risks, and its proposed mitigation options.[17]

To develop its bundled service customer energy forecast for this Application, SCE used a retail customer sales forecast completed in December 2022, consisting of forecast sales to bundled service customers and Departing Load customers measured at the customer meter (the former being functionalized as "generation service," and the latter "delivery service."). Total retail electricity sales in SCE's service territory totaled 85,996 gigawatt hours (GWh) in 2022. For 2023 and 2024, SCE forecasted sales of 82,966 GWh and 83,762 GWh, respectively.[18] The decrease in 2023 was a result of a normal weather assumption relative to 2022's extremely hot summer weather conditions. The forecasted increase in 2024 was attributed to a forecasted increase in electricity consumption from a higher number of climate change-driven cooling degree days and increased transportation electrification load.[19]

SCE calculated the revenue requirement necessary for procuring bundled customer energy in 2024 using energy need at the California Independent System Operator (CAISO) interface. This methodology enabled SCE to account for line losses inherent in transporting energy from the CAISO interface to bundled service customers' meters.[20] SCE's retail sales forecast is also influenced by

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[17] Exhibit SCE-01C at 3-4.

[18] Exhibit SCE-06C at 15 confirmed that SCE's forecasted retail electricity sales are unchanged from its original testimony. However, SCE noted in its October 24, 26, and October 31, 2023, errata that it did not accurately remove the City of Huntington Beach customers from its bundled customer forecasts, and the necessary adjustments are noted throughout this Decision.

[19] Exhibit SCE-01C at 13.

[20] Exhibit SCE-01C at 13.

historical trends in employment growth, residential housing starts, the economic outlook, weather assumptions, and other factors (*e.g.*, energy efficiency (EE) savings, spending on wildfire mitigation, grid safety and resiliency).

SCE then applied a downward adjustment to its retail sales forecast to account for the 4.45 percent difference between the delivered and billed kilowatt hours (kWh) for customers enrolled in net energy metering (NEM). This sales adjustment was slightly reduced to 4.3 percent in SCE's October Update, to be applied to sales used for bundled and Departing Load customers. NEM bills are calculated as the net of energy delivered to the site and energy exported from the site to the grid. This NEM billing adjustment is applied to sales for both bundled and Departing Load customers, as it reduces the level of sales available to recover authorized revenues for all retail sales, thereby affecting the forecast of total energy costs.[21] The NEM downward adjustment for bundled customers was forecasted to be approximately 5.2 percent.[22]

SCE's forecast also accounted for the statewide increase in the Direct Access load cap, which started in 2021.[23] It also included Energy Service Providers and Community Choice Aggregators (CCA) that met 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 § 380.[24] In its October Update, SCE noted that Orange County

[21] Exhibit SCE-01C at 14-15 and Exhibit SCE-06C at 16-17.

[22] Exhibit SCE-01C at 14-15 and Exhibit SCE-06C at 16-17 and footnote 23.

[23] Exhibit SCE-01C at 14.

[24] SCE included the following CCAs in its 2024 ERRA forecast: Lancaster Choice Energy (LCE); Apple Valley Choice Energy (AVCE); Pico Rivera Innovative Municipal Energy (PRIME); Clean

Power Authority (OCPA) provided notice on September 29, 2023, with a six-month advance notice of its intent to involuntarily return 4,228 NEM accounts to SCE's procurement service. Due to the date of that notice as compared to the deadline for SCE to file the October Update in this proceeding, SCE noted that this mass return of NEM customers will result in an underestimation of 2024 bundled service load forecast and associated costs, which could be partially offset by higher-than-forecasted customer revenue in 2024.[25]

As with its past ERRA forecast applications, SCE forecasted energy production from its portfolio using a software model to (1) forecast the least-cost dispatch (LCD) of dispatchable resources in SCE's portfolio; (2) optimize hydro dispatch; and (3) perform Monte Carlo simulations of forced outage rates of individual units. The price for natural gas was based on monthly New York Mercantile Exchange (NYMEX) forward prices at the SoCal City gate plus intrastate transportation charges from Southern California Gas Company, where applicable. It forecasted dispatch of SCE utility-owned and contracted generation resources in a least-cost manner, using forward power broker quotes for 2024 to generate hourly price profiles.[26]

Power Alliance (CPA) Phases 1-5; San Jacinto Power (SJP); Rancho Mirage Energy Authority (RMEA); Central Coast Community Energy (3CE); Pomona, Palmdale Phases 1 and 2; City of Santa Barbara; Orange County Power Authority Phase 1, 2, and NEM. Huntington Beach withdrew from OCPA in May 2023. CPA also submitted an implementation plan for its Phase 6 service to begin in 2024 in Hermosa Beach, Monrovia, and Santa Paula. SCE provided a summary of meetings with CPA and OCPA in the workpapers of A.23-06-001. (*See* Exhibit SCE-01C at 24 and Exhibit SCE-06C at 18-19).

[25] Exhibit SCE-06C at 19 and footnote 25.

[26] SCE used the software PLEXOS to forecast LCD of dispatchable resources in SCE's portfolio; optimize hydroelectric resource dispatch; and perform Monte Carlo simulations of forced outage rates for individual units. Energy- and use-limited hydroelectric and gas peaking resources were also modeled to dispatch pursuant to LCD. The 24-hour flat price forward

SCE also proposed to return a total of approximately $955.105 million in net greenhouse gas (GHG) allowance revenues to applicable customers in 2024, which would result in a semi-annual bill credit of $86.00 to eligible residential and small commercial customers.[27] Its forecasted GHG allowance rate was based on the Intercontinental Exchange (ICE) settlement price for a 2024-vintage GHG allowance. The GHG forecasted costs, revenues, and reconciliation are discussed in more detail in Section 7 below.

In a related action, on April 6, 2023, the Commission adopted D.23-04-012, authorizing SCE's 2023 ERRA Trigger Application (A.23-01-020), authorizing the utility to increase its bundled service customer generation rates by up to $595.615 million effective June 1, 2023, in an effort to maintain SCE's ERRA Trigger Mechanism Thresholds.[28] On May 15, 2023, SCE submitted Advice Letter (AL) 5036-E, setting an ERRA Trigger Threshold of $454 million to be added to bundled service customers' generation rates effective June 1, 2023. SCE stated that implementation of AL 5036-E reset its forecast ERRA Trigger to zero, and that it expected to recover the authorized $454 million over a 12-month period (June 1, 2023-May 31, 2024). The June 2023 rate increase approved in D.23-04-012 and AL 5036-E was only applied to bundled service customer generation rates, not any departing load customers.[29] Further, SCE removed the increased revenue

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power broker cost was $67.57/MWh for 2024. *See* Exhibit SCE-06C at 24 and footnotes 29 and 31.

[27] D.14-10-033, Ordering Paragraph 10 and Exhibit SCE-06C at 1.SCE noted that the ICE settlement price of a 2024-vintage GHG allowance as of August 24, 2023 was $39.36 per metric ton. The GHG price forecast was incorporated as part of the resource dispatch costs, like natural gas prices, in order to reflect the appropriate costs for GHG-emitting resources. *See* Exhibit SCE-06C at 24, footnote 30.

[28] D.23-04-012, Ordering Paragraph 1.

[29] Exhibit SCE-01C at 5.

associated with the ERRA Trigger revenue requirement in 2023 from its estimate of the 2023 year-end balance in the ERRA BA used to set the 2024 ERRA forecast rates, to avoid double-counting.[30]

Upon review, we find SCE's 2024 ERRA forecast methodology, including its accounting of D.23-04-012, to be reasonable and in line with existing Commission orders and regulatory requirements.

5. SCE's Portfolio of Resources for 2024

SCE's portfolio of resources includes a variety of utility-owned and contracted resources, which are discussed in Sections 5.1-5.12 below. Each section describes the costs associated with each resource that were proposed in SCE's 2024 ERRA Forecast Application and Testimony as amended in its October 2023 Update.[31]

5.1. Utility-Owned Generation and Purchased Power Contracts

SCE's utility-owned generation (UOG) and purchased power contract resources consist of hydroelectric; fuel cells; combined heat-and-power (CHP) and renewable resources; nuclear; natural gas; and battery storage. As discussed in Section 4 above, SCE forecasted dispatch of its portfolio of resources using an LCD approach.

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[30] Exhibit SCE-01C at 5.

[31] In Exhibit SCE-06CE2 at 125 and Table IX-42, SCE noted that (1) the change in its Total Portfolio Costs between its June Testimony (Exhibit SCE-01C) and its October Update is a two percent increase and (2) its October Update forecast of the value of its Total Portfolio Market Value increased by approximately 12 percent compared to its June Testimony. The increase in Total Portfolio Market Value is largely associated with the higher 2024 MPB adopted by the Commission's Energy Division on October 2, 2023.

5.1.1. Hydroelectric Resources

SCE's hydroelectric resources consist of 33 powerhouses in Central and Southern California that provide a combined 1,176 megawatts (MW) of nameplate capacity. SCE forecasted normal hydrological conditions in 2024.[32]

SCE's 2024 forecast optimized the use of the full 1,015 MW of capacity from the nine-unit Big Creek Project, located about 50 miles east of Fresno, California (when operationally feasible) during the highest economic value hours. When Big Creek's capacity is not operating at full capacity, it can be used to provide ancillary services to the CAISO market. Pumpback necessary to operate the 199.8 MW Eastwood powerhouse occurs during off-peak hours and dispatch occurs during peak hours, to optimize the differential in energy prices. The Eastwood powerhouse had a circuit breaker failure in September 2022 that caused a forced outage. It is currently forecast to resume operations in January 2024.[33]

The other 24 powerhouses are in SCE's Eastern Division. Its Eastern Division powerhouses are in the Sierra Nevada, San Bernadino, and San Gabriel mountains and provide 161 MW of run-of-the-river, non-dispatchable resources.[34]

5.1.2. Solar Photovoltaic Generation

D.13-05-033 authorized SCE to install, own, and operate up to 91 MW of direct current solar photovoltaic (SPV) generation on commercial rooftop space and/or ground mounts within its service territory. There is a large pending sale

[32] Exhibit SCE-01C at 35.

[33] Exhibit SCE-01C at 33-34.

[34] *Ibid.*

of its UOG SPV resources that is reflected in SCE's 2024 ERRA forecast.[35] SCE expects that all sites except site 42 will be de-energized due to the pending sale, which it reflected in its energy forecast.[36] Its 2024 forecast included approximately 9 MW of direct-current SPV from its UOG resources.

5.1.3. Combined Heat-and-Power (Co-Generation) and Renewables

SCE forecasted the power deliveries from its co-generation and renewable resources as "must-take" energy, measured at the generators' meters. The projects SCE included in its 2024 forecast total approximately 10,071 MW of contracted capacity, representing historical performance of existing resources. Three additional projects, totaling approximately 52 MW, are expected to begin delivering energy between January and December 2024, but the contractual expectations of deliveries from those new projects was adjusted to account for their expected probability of successful development and commercial operation.[37] SCE's ERRA forecast also accounted for estimated curtailments from its contracted solar and wind resources due to economic reasons.[38]

SCE's renewable and combined heat-and-power (CHP) projects typically have contract-specific energy prices, but it also has a number of qualifying facility (QF) projects that are paid at the posted avoided cost of energy price under standard offer contracts (SOC). The SOC is either based on the New QF SOC adopted in D.20-05-006, which is based on a three-year average of CAISO

[35] Exhibit SCE-01C at 35.

[36] Exhibit SCE-06C at 32-33.

[37] Exhibit SCE-01C at 36-37.

[38] Exhibit SCE-01C at 41,

locational marginal prices, or the QF SOC adopted in the QF Summit settlement, which is based on average 12-month forward heat rates for the resource type.[39]

SCE forecasted the annual capacity factors for its CHP and renewable energy projects as follows:

Annual Capacity Factors by Technology[40]

Technology Type	Percent Capacity Factor
Biomass	77.4%
Cogeneration	19.0%
Geothermal	85.6%
Small Hydro	23.9%
Solar	30.1%
Wind	28.4%

SCE noted that its energy and capacity prices for each of the CHP and renewable energy projects in its portfolio are based on the individual contracts and that its forecast includes estimated curtailments from its solar and wind portfolios due to economic reasons, which are reflected in SCE's energy and payment forecasts.[41]

5.1.4. Natural Gas and Interagency Contracts

SCE included the natural gas procurement costs for its five black-start capable peakers within its 2024 ERRA forecast. The five natural gas peakers have a combined capacity of 245 MW.[42] The non-fuel variable costs associated with

[39] Exhibit SCE-01C at 39-40.

[40] Exhibit SCE-06C at 34.

[41] Exhibit SCE-06C at 36 – 38.

[42] The Commission ordered SCE to build up to 250 MW of black-start capable, dispatchable generation capacity within its service area through an August 15, 2006, Assigned Commissioner's Ruling. Exhibit SCE-06C at 38.

these peakers are included in SCE's General Rate Case (GRC) revenue requirement.[43]

Other than the peaker plants, SCE owns the Mountainview Generating Station and proposed to continue recovering capital and fuel costs, pursuant to D.18-10-019.[44]

In its October Update, SCE noted that gas prices for 2024 are expected to be approximately four percent higher than those forecasted for 2023.[45]

SCE also has a contract through September 2067 to purchase and/or exchange capacity from the Hoover Dam with the Western Area Power Administration and the U.S. Bureau of Reclamation (WAPA-Reclamation). To account for the ongoing drought conditions affecting the Hoover power plant, SCE forecasted approximately 117 MW of contingent capacity and 8 GWh of firm energy for 2024.[46]

5.1.5. Resource Adequacy Contracts

D.06-07-029, as modified by D.10-12-035 and Senate Bill 695 adopted a cost allocation mechanism (CAM) to allocate the costs electric utilities incur to meet Resource Adequacy (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.

Under a Joint Party Proposal adopted in D.07-09-044, SCE will hold the dispatch rights for all New Generation contracts in 2024, but the energy from

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[43] Exhibit SCE-01C at 41 and Exhibit SCE-06C at 38-39.

[44] Exhibit SCE-06C at 38-39 and Table IV-8 and IV-9.

[45] Exhibit SCE-06C at 6.

[46] Exhibit SCE-01C at 42-43 and Exhibit SCE-06C at 39-40 and Table IV-14.

these contracts was not used to meet forecasted bundled customer load.[47] Instead, SCE forecasted the energy revenue benefits from these resources to be allocated to all customers, and energy revenues from these resources were based on LCD.

SCE also forecasted that its DESI 2, or UOS Titanium project, will be a CAISO market resource of 1.4 MW/ 3.7 MWh, and stated it will recover storage charging costs and market revenues associated with this resource through its NSGBA.[48]

5.1.5.1. System Reliability Request for Offers

SCE forecasted 2024 costs associated with resources procured in accordance with D.19-11-016's order directing utilities to conduct System Reliability Request for Offers (SRRFO). D.19-11-016 directed SCE to procure 1,184.7 MW of incremental RA capacity, including seven "Fast Track" contracts for new energy storage resources (totaling approximately 678 MW of incremental RA system capacity) that were approved in Resolution E-5101, and an additional five "Standard Track" contracts that were approved in Resolution E-5142 (totaling approximately 590 MW of nameplate capacity).[49] Pursuant to Resolution E-5240, SCE accounted for emergency system reliability Modified

[47] Exhibit SCE-06C at 41.

[48] Exhibit SCE-06C at 41.

[49] *See* Exhibit SCE-06C at 41-42. Pursuant to D.19-11-016, "Fast Track" projects were to come online by August 1, 2021; "Standard Track" projects were to come online by August 1, 2022, and August 1, 2023. Pursuant to an April 15, 2020, ALJ Ruling in Rulemaking 16-02-007, SCE was also required to procure an additional 56.6 MW for the customers of opt-out load-serving entities.

Cost Allocation Mechanism (MCAM)-eligible costs and revenues in its 2024 forecast.[50], [51]

5.1.5.2. Emergency Reliability

D.21-02-028 authorized the investor-owned utilities (IOU) to contract for emergency reliability 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 further 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.

5.1.5.3. Mid-Term Reliability

D.21-06-035 addressed mid-term reliability needs across CAISO's operating system, and SCE launched its Mid-Term Reliability Request for Offers (MTRRFO) for incremental resources to come online in 2023-2024 on July 30, 2021.[52],[53] SCE has executed contracts for several energy storage and renewable energy projects to address mid-term reliability needs, which were approved in Resolutions E-5205, E-5225, E-5234, E-5251, E-5253, and E-5271.

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[50] Exhibit SCE-01C at 44-45 and Exhibit SCE-06C at 42-43. Resolution E-5240, approving Advice Letter 4831-E/E-A, authorized SCE to transfer the cost recovery of the System Reliability Procurement Memorandum Account (SRPMA) recorded costs to its PABA, MCAMBA, and NSGBA. SCE completed these cost transfers in January 2023 and June 2023. SCE is no longer recording costs in the SRPMA and will seek to eliminate the SRPMA in a future filing.

[51] Exhibit SCE-06C at 43. SCE allocated the SRRFO costs to its bundled service and load-serving entity opt-out customers based on their pro-rata load share.

[52] D.21-06-035 required at least 11,500 MW of additional net qualifying capacity (NQC) to be procured by all of the LSEs subject to the Commission's integrated resource planning (IRP) authority. SCE's portion of that capacity is 4,052 MW: 705 MW online by August 1, 2023; 2,114 MW by June 1, 2024; 529 MW by June 1, 2025, and 705 MW of long lead time resources by 2026.

[53] Exhibit SCE-06C at 44. SCE's MTRRFO sought zero-emitting resources or resources that otherwise qualify under RPS eligibility requirements.

5.1.5.4. Generic and Bilateral Resource Adequacy Contracts

SCE forecasted its 2024 RA purchase costs for generic and bilateral RA contracts using the RA MPB and the revenue from sale of excess RA. It calculated its 2024 month-ahead RA position based on its RA requirements and the available supply it has contracted to meet them, plus a buffer. SCE also included forecasted costs associated with its local capacity requirements (LCR) contracts in the Western LA Basin and Moorpark local reliability areas. [54]

In testimony, CalCCA questioned whether SCE properly accounted for the 537.5 MW of utility owned storage that was initially connected to non-CAISO controlled distribution assets but may eventually become CAISO market assets in 2024 or future years, suggesting that the costs should be credited against distribution costs, rather than reducing bundled customer load procurement costs.[55] SCE addressed this concern in its rebuttal testimony and its October Update, and clarified in its opening comments on the Proposed Decision that the UOS projects that will be distribution assets in 2024 will not be recovered through the PCIA.[56]

5.1.6. Discussion

No parties directly addressed SCE's testimony and workpapers related to its hydroelectric, SPV, CHP, or natural gas and interagency contracts. After reviewing the workpapers and October Update documents, we find SCE's forecasted 2024 portfolio of UOG and purchased power resources to be reasonable pursuant to Pub. Util. Code § 454.5.

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[54] Exhibit SCE-01C at 48-49 and Exhibit SCE-06C at 46-47 and Table IV-9.

[55] Exhibit CalCCA-01C at 3-4.

[56] *See* Exhibit SCE-05C at 7-10, Exhibit SCE-06C3 at 124-125, and SCE November 17, 2023, Opening Comments at 3.

Upon review of the testimony and rebuttal from CalCCA and SCE filed in this proceeding, and SCE's October Update, we find the RA Contracts SCE included in its 2024 ERRA forecast to be reasonable and in compliance with legislative and regulatory requirements. SCE is also directed to separate the charging cost and use the Energy Index MPB to forecast the value of discharging the battery as proposed in Exhibit SCE-05C and discussed further in Section 6.4.1 below.

5.2. Public Purpose Program Charges

SCE forecasted procurement-related expenses for the four programs it recovers through the Public Purpose Program charge (PPPC) in 2024.

First, SCE included forecasted capacity costs and estimated in-front-of-the-meter production of resources procured through its Preferred Resource Pilot (PRP) #2.[57] These resources were procured pursuant to D.18-07-023 which authorized SCE's second PRP. SCE proposed to recover the costs of the PRP behind-the-meter energy storage contracts from customers through the PPPC.[58]

Second, SCE included forecasted at total of $4.581 million in fuel and purchased power costs to be recorded in the TMNBCBA, including the Franchise Fee and Uncollectible Factor (FF&U).[59]

Third, pursuant to Resolutions E-4805 and E-4770, SCE forecasted audit expenses for its BioRAM contracts to total $0.018 million in 2024, but the actual

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[57] Preferred Resources are defined as cost-effective EE, demand response, renewable resources, and distributed generation. *See* State Energy Action Plan II at 2 and Exhibit SCE-01C at 49.

[58] Exhibit SCE-06C at 48 and footnote 52.

[59] SCE has three tree mortality contracts. *See* Exhibit SCE-01C at 120 and Exhibit SCE-06C at 117-118. These were procured pursuant to Resolutions E-4770 and E-4805.

audit expenses will be recorded in its TMNBCBA.[60] SCE forecasted a total undercollection of $10.588 million in its TMNBCBA at the end of 2023.[61]

Fourth, SCE projected the fuel and purchased power costs related to its Bioenergy Market Adjusting Tariff (BioMAT) Resources or Contracts to total $4.118 million in 2023, including FF&U. SCE estimated an overcollection in its BMNBCBA of $6.689 million in 2023. [62]

Preferred Resource Pilot Program BA (PRPPBA), TMNBCBA or BMNBCBA in testimony. Upon review of SCE's testimony, October Update, and Workpapers, the Commission finds SCE's forecasted 2024 PRPPBA, TMNBCA, and BMNBCBA amounts reasonable. SCE is authorized to recover its costs associated with the programs described in Section 5.2 above through the PPPC.

5.3. Green Tariff Shared Renewables Program

SCE included the costs of implementing its Green Tariff Shared Renewables (GTSR) Program, pursuant to Public Util. Code § 2831-2833 and D.15-01-051. SCE provides customers with two options to be served with a larger mix of renewable energy, relative to SCE's other tariff options. Under SCE's Green Rate program, customers may choose either a 50 percent or 100 percent mix of renewable energy, with a corresponding increase in their generation rate. Under SCE's Enhanced Community Renewables (ECR) option, customers may support local renewable energy projects through agreements with third-party developers.[63] SCE has procured Green Tariff-specific projects to serve GTSR

[60] Exhibit SCE-06C at 118.

[61] Exhibit SCE-06C at 119-120.

[62] Exhibit SCE-06C at 117-120 and Confidential Appendix A of SCE's October Workpapers.

[63] SCE will not begin serving customers under its ECR option until ECR-specific projects reach commercial operation. *See* Exhibit SCE-06C at 48, footnote 54.

customers that are expected to be producing power in 2024, but SCE noted these projects are still pending Commission approval and have therefore not been included in SCE's forecast. [64]

For 2024, SCE forecasted that participation in its Green Tariff programs will equal approximately 171.2 MWh and will be serviced by resources that are already online and are not already being accounted for in the CHP and renewable energy costs and power resources described in Section 5.1.3 above. SCE withdrew its petition to modify D.15-01-051 on August 9, 2023, and did not include any additional capacity or related costs related to the relief it had requested in its petition in the forecasts provided in its October Update.[65]

No party directly referenced SCE's Green Tariff programs in their testimony or briefs. Upon review of SCE's testimony, October Update, and Workpapers, the Commission finds SCE's forecasted 2024 GTSR BA amount accurate, reasonable, and in compliance with applicable rules and Commission orders.

5.4. Nuclear

SCE owns a 15.8 percent share, or 213MW per unit, of the three-unit Palo Verde Nuclear Generation Station (PVNGS), which is operated by Arizona Public Service Company (APS). SCE forecasted that PVNGS will operate at baseload capacity in 2024, but for two refueling outages.[66] SCE, through contracts

[64] The weighted average price of the GTSR program was calculated based on contracts specifically for GTSR resources, excluding the projects that have not yet been approved by the Commission. Exhibit SCE-06C at 48.

[65] Exhibit SCE-06C at 49. SCE stated the relief sought in its August 6, 2022, PFM was no longer timely.

[66] Exhibit SCE-01C at 51. PVNGS Unit 3 has a scheduled refueling outage commencing April 6, 2024, and PVNGS Unit 2 has a scheduled refueling outage commencing October 5, 2024.

with APS and other suppliers, incurs a share of the nuclear fuel management costs for PVNGS, from the mining of the uranium necessary to fabricate the fuel to spent fuel transportation, safe interim storage, and permanent disposal. SCE projected that its share of the PVNGS nuclear fuel expense for 2024 will be $29.7 million.[67] The costs to transfer fuel to, and store it in, the on-site Independent Spent Fuel Storage Installation (ISFSI) are considered operating costs for PVNGS, and therefore not included in the 2024 ERRA forecast. However, SCE forecasted it will incur $2.915 million in spent nuclear fuel storage costs associated with PVNGS, approximately $2.907 million of which would be offset by credits from the U.S. Department of Energy spent fuel litigation. Therefore, SCE included a net cost associated with PVNGS spent fuel storage of $0.008 million.[68]

Separately, SCE is the majority owner and decommissioning agent for the San Onofre Nuclear Generating Station (SONGS) Units 1, 2, and 3. SONGS Unit 1 was retired on November 30, 1992, and SONGS Units 2 and 3 were permanently retired on June 7, 2013. All three SONGS units are being decommissioned, and the fuel from the units has been transferred to its on-site ISFSI. The costs for storing spent fuel at the on-site ISFSI are covered by the SONGS Nuclear Decommissioning Trusts and were not included in the 2024 ERRA forecast. However, SCE included $4.894 million in off-site interim storage costs for SONGS Unit 1 spent fuel assemblies in its 2024 ERRA forecast.[69]

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[67] Exhibit SCE-06C at 51 and Table IV-16.

[68] Exhibit SCE-01C at 51-54 and Table IV-15, as updated by Exhibit SCE-06C at 52 and Table IV-16.

[69] Exhibit SCE-01C at 54 and Table IV-15 and Exhibit SCE-06C at 52 and Table IV-16.

No parties addressed SCE's nuclear-related cost forecasts for 2024. Upon review, we find SCE's proposed costs associated with fuel storage and procurement for PVNGS and off-site interim storage costs for SONGS to be reasonable and in accordance with state laws and regulations. SCE is authorized to recover up to $4.9 million in spent nuclear-fuel storage related costs in 2024, and its forecasted fuel procurement costs are approved.

5.5. Catalina Fuel Costs

SCE uses six diesel generators and 23 propane-fired micro-turbines at the Pebbly Beach Generating Station to provide electricity service to Santa Catalina Island. Based on historical usage rates in 2022-2023 and the island's storage capacity, SCE forecasted it will need to acquire 50,436 barrels of diesel fuel throughout 2024 in the Los Angeles market, at a cost of approximately $179.91/barrel, or $9.040 million total. SCE also estimated it will need to procure approximately $0.404 million in propane fuel.[70] Both the diesel and propane cost projections were based on the IHS Global Insight Variable for Gasoline and Fuels and add to $9.444 million in fuel costs to service Catalina Island in 2024.[71]

No parties addressed SCE's forecasted 2024 fuel costs for its service to Santa Catalina Island in comments or testimony. Upon review, we find the forecasted propane and diesel fuel costs to be reasonable and appropriately modeled using market-based pricing and authorize SCE to recover them as proposed.

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[70] SCE's forecast suggested a total estimated propane cost of $0.66 million for 2024, but it projected propane costs will decrease by approximately 38.53 percent through 2024, resulting in its 2024 propane forecast of $0.404 million for Catalina Island micro-turbine generation. *See* Exhibit SCE-06C at 55 and Table IV-17.

[71] Exhibit SCE-01 at 54-59.

5.6. Demand Response

SCE forecasted an estimated 6 GWh of energy reductions in 2024 through several price-responsive demand-response (DR) programs: Summer Discount Plan (SDP), Smart Energy Program (SEP), and Capacity Bidding Program (CBP). SDP and SEP are bid into the CAISO markets as Reliability Demand Response Resource (RDRR) and CBP as Proxy Demand Resource (PDR).[72] The impact of these programs is based on past customer performance and enrollment, which can vary month-to-month. Pursuant to D.17-12-003, SCE records all demand response incentives in its Demand Response Program Balancing Account (DRPBA), and the annual balances are transferred to the BRRBA. SCE's 2024 DR forecast was based on its Load Impact Protocols and opportunity costs that factor in the maximum available hours for customers to participate in specific programs per day, month, and year.[73]

No parties directly contested SCE's forecasted DR energy reductions or its forecast calculations. Upon review of Commission precedent and SCE's filings in this proceeding, we find its DR forecasts for 2024 to be reasonable and therefore adopt them.

5.7. CAISO Costs, Load Procurement Charges, and Energy Revenue

SCE separated CAISO-related costs into (1) non-energy related costs; (2) load-procurement charges; and (3) energy-related revenues associated with SCE's PABA- and CAM-eligible resources.[74]

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[72] *See* CAISO Business Practice Manual for Demand Response, *Overview of Demand Response Resources*, Exhibit SCE-01C at 59, and Exhibit SCE-06C at 57-58.

[73] Exhibit SCE-06C at 57 and D.08-04-050, Attachment A.

[74] SCE noted that it applied different forecasting methodologies for the separate CAISO cost types. Exhibit SCE-06C at 58, and footnote 58: "Consistent with D.18-10-019, SCE now forecasts

SCE stated that non-energy-related CAISO costs are not sensitive to short-term energy market prices, and therefore its 2024 forecast for such costs will be equal to the most recent 12-month period.[75]

SCE calculated load-procurement charges for 2024 by multiplying the hourly load by the hourly SP-15 prices for each hour. Pursuant to Resolution E-5183, SCE contracted to develop 537.5 MW of energy storage to address summer reliability. SCE stated it will credit energy benefits associated with these storage assets against the costs that are recovered through distribution charges, and reduce load-procurement charges that apply to bundled service customers to reflect the net benefits.

Finally, SCE estimated its energy revenue by multiplying the forecasted production from its PABA-, ERRA-, BMNBC-, CGST-, and CAM-eligible portfolios by the SP-15 price at that hour. The energy revenues are used to offset forecasted PABA, ERRA, BMNBC, CGST, and NSGBA revenue requirements.[76]

CalCCA raised some concerns related to the revenues associated with SCE's utility-owned storage facilities, which are directly addressed in Section 6.1.2, below. Otherwise, no party directly addressed SCE's forecasted 2024 CAISO costs, load procurement charges, or energy revenue. Upon review of SCE's testimony, rebuttal testimony, October Update, and workpapers, we find

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energy revenues separately from load procurement charges, as the energy revenues for PABA-eligible resources are recorded to PABA, while load procurement charges are recorded to the ERRA BA."

[75] Exhibit SCE-01C at 60 and Table IV-8. For 2024, SCE's forecasted non-energy-related CAISO costs were comprised of the net costs of grid management charges (GMC); Federal Regulatory Commission (FERC) fees; Congestion Revenue Rights (CRR) auction-related costs; ancillary services; CAISO uplift costs; standard capacity product (SCP) costs; and other non-energy-related CAISO costs.

[76] Exhibit SCE-01C at 61 and Table IV-8.

its forecasted 2024 CAISO-related costs to be reasonable and therefore approve them as proposed.

5.8. Hedging Costs

SCE's costs of power and natural gas for its UOG, purchased power contracts, and QF contracts are hedged using the underlying commodities trading markets to offset risks of market volatility. The hedging costs for 2024 include brokerage fees and options premiums. No party addressed this issue directly. Upon the Commission's review of SCE's documents, we find the hedging costs forecasted for 2024 to be reasonable, and therefore approve its proposed continuation of its market-based approach to manage its hedging costs.

5.9. Gas Transportation and Storage

SCE forecasted it will enter into new gas transportation agreements in 2024 that will cost approximately $12.058 million for both SCE-owned and contracted facilities, based on the daily reservation charge for Backbone Transportation Service (BTS) rights. SCE stated it intends to seek a three-year term (October 2023 – September 2026) contract with Southern California Gas Company for up to 75,000 million British Thermal Units (MMBtu) per day, which is how this estimated forecasted transportation cost was calculated.[77]

Separately, SCE has a month-to-month contract with Southern California Gas Company for gas transportation to its (1) Mountainview Plant and (2) Barre, Center, Grapeland, McGrath, and Mira Loma peaker plants. SCE forecasted these contracts to auto-renew each month in 2024.[78]

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[77] Exhibit SCE-01C at 74-75.

[78] Exhibit SCE-06C at 73. These gas transportation contracts do not have any fixed components, so the charges will vary by month.

SCE also has a BTS contract with Southern California Gas Company for firm rights of 60,000 MMBtu/day for a three-year contract (October 2023-September 2026). SCE forecasted that the total fixed costs for this contract in 2024 will be $12.058 million, and the tariff-based reservation charge is currently $0.54908/MMBtu per day.[79]

No party addressed SCE's gas transportation and storage forecasts directly in filings. Upon the Commission's review of SCE's documents, we find its forecasted 2024 gas transportation and storage costs to be reasonable and therefore approve them as proposed in A.23-06-001 and updated in SCE's October Update.

5.10. Subscription Fees, Financing Costs, and Carrying Costs

SCE forecasted that it will spend up to $529,000 on subscription fees to access market data, risk analysis, reports on power, gas, and GHG allowance price forecasts, and other industry news in 2024.

Separately, SCE is authorized to recover actual fuel inventory financing costs and actual collateral costs, pursuant to D.93-01-027, D.02-10-062, and D.04-01-048. The latter Decision directs SCE to apply the three-month commercial paper rate index to undercollected balances. SCE forecasted it will use a portion of a $3.35 billion multi-year revolving credit facility to provide capacity for collateral and supporting account balances and requested to recover various fees and upfront costs associated with that portion in its 2024 ERRA proceeding-related balancing accounts. In 2023, SCE exercised an option to extend this revolver one additional year with the following features:

[79] Exhibit SCE-06C at 73. These rates and SCE's forecasted costs reflect Southern California Gas Company's Rate Schedule G-BTS2.

1. $3.35 billion borrowing capacity;
2. May 2027 maturity;
3. $20,000 annual administrative fee;
4. 17.5 basis point annual facility fee;
5. 107.5 basis point participation fee on any outstanding letters of credit;
6. 20 basis point issuer fees on any letters of credit; and
7. Adjusted Daily Simple Secured Overnight Financing Rate plus 107.5 basis points loan rate.[80]

SCE also stated it will use its $3.00 billion commercial paper program to finance fuel inventories in 2024, assuming the market for A2/P2 commercial paper remains stable and SCE can use this program for short-term financing needs.[81]

SCE separately forecasted fuel inventory carrying costs for nuclear, natural gas, and diesel; GHG procurement compliance carrying costs for 2024, which SCE estimates using historical GHG inventory balances and the ERRA BA interest rates; and the carrying costs associated with SCE's collateral requirements necessary to procure power.[82]

No party directly addressed SCE's forecasted subscription fees, financing costs, or carrying costs as described in its testimony, workpapers, and October Update documents. Upon review, we find its 2024 forecasts for subscription fees; financing costs; and carrying costs for 2024 as described above to be reasonable and therefore approved for 2024.

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[80] Exhibit SCE-01C at 77-79 as updated by Exhibit SCE-06C at 75-76.

[81] Exhibit SCE-01C at 79 and Exhibit SCE-06C at 76-77.

[82] Exhibit SCE-01C at 80-82.

6. SCE's Revenue Requirement and Ratemaking Proposal

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 SCE's ERRA BA; PABA; and (3) the GTSR BA. SCE's 2024 forecast generation service requirement, as provided in its October Update, is $5.513 billon, which is $567.214 million, or 9.33 percent, below its generation service revenue requirement from rates in effect today. The impacts on SCE's customer groups associated with this revenue requirement are detailed Section 10, below.

6.1.1. ERRA Balancing Account

SCE's 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.[83] In its 2024 forecast, SCE estimated the ERRA BA will be undercollected by $207.835 million (including FF&U) at the end of 2023.[84] This estimate was developed by adding the amount forecasted to be recorded in the ERRA BA May-December 2023 to the amount already recorded as of September 30, 2023, which included the RA and RPS true-up amounts. To these recorded amounts, SCE added the forecasted amounts for October, November, and December 2023. More discussion of the RPS value and the Voluntary Market Allocation Offer (VAMO) process is included in Section 6.5.

[83] SCE's ERRA BA was established in D.02-10-062, effective January 1, 2003.

[84] Exhibit SCE-06CE2 at98, Table VIII-35.

SCE noted that the undercollection is largely due to the true-up of RA adders, which added approximately $688.396 million to its ERRA BA.[85] These adders are discussed in more detail in Section 9, below.

As discussed in Section 4 above, SCE removed the increased revenues associated with the 2023 ERRA Trigger revenue requirement when calculating its final ERRA BA balance for 2023.

Table 6-2. Summary of SCE's Proposed 2024 ERRA Forecast Proceeding Generation Service Revenue Requirement[86]

Description	SCE Proposed 2024 Revenue Requirement
2024 F&PP Costs (including GHG costs) • ERRA BA-related • PABA-related • Green Tariff Shared Renewables BA-related	 $4.459 billion $235.097 million $9.741 million
2023 ERRA BA True-up	$207.835 million
2023 PABA True-Up	$601.728 million
2023 ESMA True-Up	-$380,000
Total Generation Service	**$5.513 billion**

6.1.2. Portfolio Allocation Balancing Account

D.18-10-019 modified the balancing accounts to be considered in ERRA forecast proceedings and directed utilities to create new balancing accounts to

[85] Exhibit SCE-06C at 105, Table VIII-35, and Appendix A tab 1.

[86] Exhibit SCE-05 at 10, Exhibit SCE-06C at 98, Table VIII-35 and Appendix A tab 1, and Exhibit SCE-06CE2 at 98 and Table VIII-35.

track above-market costs and revenues associated with their electric portfolios.[87] These PABA record 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). In its 2024 ERRA Forecast, SCE estimated the balance in its PABA will reflect an undercollection of $235.097 million, including FF&U, as of December 31, 2023.[88] This estimate includes a debit of $2.948 million associated with an undercollection from departing load customers that SCE was directed to track and recover in its PUBA over a 36-month period. In its 2024 ERRA forecast application, SCE requested to transfer the remaining PCIA Undercollection BA (PUBA) balance to the One-Time Refunds/Costs Applicable to All Customers sub-account of its PABA.[89]

CalCCA noted that while SCE projected its PABA account balance would decline over the course of 2023, the latest actual results show the PABA balance had increased above SCE's initial projections.[90] SCE's October Update explained that the undercollection forecasted in its PABA over 2023 is primarily the result of lower-than-forecast CAISO market revenues and lower-than-forecast billed customer revenues. SCE also stated the December 2022 ERRA BA year-end balance that was transferred to the PABA in January 2023 was higher than forecasted last year. Further, SCE noted the undercollection in its PABA would

[87] Pursuant to D.18-10-019 Ordering Paragraph 1 and page 42, the above-market costs of the CTC- and PCIA-eligible resources are defined as the actual costs less (1) actual revenues received through bilateral transactions; (2) actual energy and ancillary services revenues; (3) actual retained RPS value; and, (4) actual retained RA value.

[88] Exhibit SCE-01C at 110 and Appendix A, Table 2. This forecast used the methodology adopted in D.22-01-003.

[89] Exhibit SCE-01C at 133.

[90] Exhibit CalCCA-02C at 31-32, referencing SCE's Confidential Appendix A Workpapers PABA tab and its July 2023 PABA PUBA Activity Report.

have been larger absent the true-up it recorded for the final RA adders in 2023, which are discussed in more detail in Section 9, below.[91]

After considering SCE's 2024 forecast application and its associated worksheets, the Commission finds SCE's forecast 2024 PABA and 2023 PABA year-end true-up reasonable and in compliance with applicable rules, orders, and Commission Decisions.

6.1.3. Geysers Contract Errors

SCE noted that it identified an error in how two of its geothermal contracts ("Geysers Power contracts") were mapped to the PABA, resulting in the revenues received from CAISO for these contracts to erroneously be recorded to the ERRA BA. This occurred largely because the contracting party modified the CAISO Schedule Coordinator ID, which SCE noted is a "very unusual and rare occurrence." SCE identified understated ERRA BA and overstated PABA balances as follows:[92]

- 2019: $8.4 million
- 2020: $73.0 million
- 2021: $124.7 million
- 2022: $212.1 million
- 2023 (January through March): $58.0 million

SCE also noted a second error when filing its 2023 ERRA Trigger. It found that its resource-specific deliveries and the associated CAISO revenues did not align for the Geysers Power contracts. There are no impacts to the ERRA BA prior to 2023, because those revenues had already been transferred to the PABA.

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[91] Exhibit SCE-6C at 107-108, Table VIII-35, and Appendix A tab 2.

[92] *See* Exhibit SCE-06C at 106. SCE noted that "All else being equal, from 2019 through 2022, this error resulted in an understated ERRA BA (because the ending balance included market revenues that did not belong there) and an overstated PABA (because it correctly had the contract costs but none of the offsetting revenues associated with the contracts)".

The corrections required to SCE's PABA net to zero in total, but there were impacts to the forecasted 2023 year-end balances in individual PABA subaccounts.[93] Ultimately, the only customers that will see an increase in their PCIA rates as a result of these errors will be customers with a responsibility for Geysers Power contracts subaccounts in 2022-2023.[94] SCE noted that after identifying these errors, it has added new internal processes intended to provide better quality control, including a trading desk notification system to alert SCE employees when a contracted resource changes its CAISO ID; monthly reviews with the CAISO settlements team; and new methods to align cost recovery with the contracted resources.[95] SCE finally noted that these errors will be addressed more thoroughly in its April 2024 ERRA Review proceeding, and the details in its 2024 ERRA Forecast were largely in the interest of transparency.[96]

6.1.4. Discussion

In its October Update testimony, SCE forecasted a $207.835 million (including FF&U) million undercollection in the ERRA BA by December 31, 2023, which SCE proposes to collect from bundled service customers in 2024. According to SCE, the undercollection results largely due to the true-up of the

[93] Exhibit SCE-06C at 108.

[94] Exhibit SCE-01C at 110, footnote 104 states: "For the average residential customer using 500 kWh per month, the estimated monthly bill impacts (decrease) associated with the correction of this error is approximately -$3/month for customers with 2014 through 2020 PCIA vintages and -$1.50/month for customers with 2021 PCIA vintages. Customers with 2022 and 2023 PCIA vintages will see a bill increase of less than $1 per month." *See* also Exhibit SCE-06C at 108 and footnote 101.

[95] Exhibit SCE-01C at 107-108. SCE also noted the same resource ID change issue affected three other contracted resources in February 2023, but that the necessary corrections made quickly enough to not affect the ERRA BA and PABA balances in this proceeding.

[96] Exhibit SCE-01C at 107.

forecasted and final RA adders, which increased its ERRA BA costs by $688.396 million.

No party directly raised concerns about SCE's proposed ERRA BA balance. Upon consideration, we find SCE's forecast ERRA BA revenue requirement and 2023 ERRA BA under/overcollection recovery proposal reasonable and in compliance with applicable rules, orders and Commission Decisions. SCE is authorized to recover the Generation Service revenue requirement summarized in Table 6-2 in 2024. Additionally, SCE is directed to address the issues associated with its Geysers Contracts Error in detail in its 2023 ERRA Compliance Review filing due on April 1, 2024.

6.2. Energy Settlement Memorandum Account and Litigation Costs Tracking Account

SCE continues to pursue refunds from generators that overcharged it and other California IOUs for electricity during the 2000-2001 California Energy Crisis. In its 2024 ERRA forecast, SCE estimated a balance of -$180,000 in its Energy Settlement Memorandum Account (ESMA), including FF&U.

Pursuant to Resolution E-3894, SCE is also required to maintain a Litigation Costs Tracking Account (LCTA) within its ESMA to track litigation costs associated with the pursuit of a settlement related to the California Energy Crisis. SCE forecasted its LCTA will have a balance of $263,000 as of December 31, 2023.

The combined balance of the ESMA and the LCTA averages to an overcollection of $380,000, which will be returned to customers.[97] No party directly raised any comments or testimony regarding SCE's forecast for its ESMA

[97] Exhibit SCE-01C at 110-111, Appendix A Table 3; and Exhibit SCE-06C at 109 and Table VIII-35.

and LCTA in 2024. We find this forecast of ESMA and LCTA balances to be reasonable and in compliance with applicable rules and regulations, and therefore approve SCE's proposal to return up to $380,000 to customers in 2024.

6.3. Delivery Service Revenue Requirement

SCE's delivery service revenue requirement is recovered from all bundled and departing load SCE customers through allocation mechanisms other than the Competition Transition Charge (CTC), PCIA, and the Wildfire Non-Bypassable Charge. SCE forecasted a total delivery service revenue requirement of -$279.280 million in 2024, which represented (1) a consolidation of NSG forecast costs, including CPE-related costs and the estimated year-end 2023 NSGBA balance; (2) 2024 System Reliability MCAM-related forecast costs; (3) 2024 Tree Mortality contract forecast costs; (4) 2024 BioMAT contract forecast costs; (5) 2024 forecast for spent nuclear fuel storage revenue requirement; (6)BRRBA-Distribution fuel and purchased power forecast costs; and (7) estimated 2024 GHG allowance revenues.[98],[99]

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[98] GHG allowance revenues and associated costs are discussed further in Section 7, below.

[99] Exhibit SCE-06C at 109 and Table VIII-35.

Table 6-3. Summary of SCE's Proposed 2024 ERRA Forecast Delivery Service Revenue Requirement[100]

Description	SCE Forecast 2024 Revenue Requirement (millions)
New System Generation • New System Generation F&PP 2024 Forecast[101] • Estimated 2023 YE NSGBA Balance • MCAM F&PP Forecast	 $402.996 $256.095 $1.313
Spent Nuclear Fuel Storage	$4.958
Distribution Rate Component • Base Revenue Requirement BA-Distribution F&PP • GHG Allowance Revenues	 -$3.582 -$955,105
Public Purpose Programs Charge • Public Purpose Program F&PP Charge 2024 Forecast • Tree Mortality Non-Bypassable Charge BA YE 2023 Balance • BioMAT Non-Bypassable Charge BA YE 2023 Balance	 $9.157 $10.588 -$6.689
Total Delivery Service	**-$279.280**

6.3.1. New System Generation Net Capacity CAM-Related Costs

D.06-07-029 established a process to allocate the benefits and costs of new generation capacity to all benefiting customers in an IOU's service area for up to 10 years. Utilities were previously required to notify the Commission whether they intend to apply this CAM to new generation capacity contracts when they

[100] Exhibit SCE-05 at 94 and Exhibit SCE-06C at Table VIII-35

[101] Estimate includes indirect GHG costs.

seek approval of each contract. In D.11-05-005, however, the Commission implemented a new process that authorizes IOUs to treat these new generation contracts as CAM-eligible for the duration of the underlying power purchase agreement, so long as the Commission finds that CAM is applicable to the contract.[102]

SCE stated that the full portfolio of 2006-2007 New Generation contracts expired in 2023, so there are no forecast capacity or energy costs, nor market revenues related to contracts pursuant to D.06-07-029 forecasted for 2024.[103]

Pursuant to D.20-06-022, SCE is the Central Procurement Entity (CPE) responsible for procuring multi-year Local RA resources on behalf of all LSEs in its distribution service area, beginning in 2023. In Exhibit SCE-02C, as updated in Exhibit SCE-07C, SCE described administrative costs and other costs associated with its role as CPE, such as system-related costs, which are recorded in its Centralized Local Procurement Sub-Account and recovered under the CAM. SCE noted that the forecasted costs only relate to Grid Management Charges associated with the CPE's participation in the RA market, since the contracts were only active for a short period prior to filing this application.[104]

6.3.2. New System Generation Balancing Account

The New System Generation Balancing Account (NSGBA) was established on January 16, 2009, pursuant to OP 2 of D.07-09-004. It is intended to record the costs and benefits of power purchase agreements associated with new generation resources, including SCE's CPE-related procurement. SCE estimated the NSGBA

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[102] D.11-05-005 at 6-7 and OP 17.

[103] Exhibit SCE-01C at 112 and Exhibit SCE-06C at 110. The specific costs associated with SCE's RA contracts are confidential.

[104] Exhibit SCE-02C at 5-6 and Exhibit SCE-06C at 111-112.

balance as of December 31, 2023, will be an undercollection of $256.095 million, including FF&U.

6.3.3. System Reliability Modified Cost Allocation Mechanism-Related Costs

As discussed in Section 5.1.5 above, D.19-11-016 established specific requirements for IOUs to procure system-level RA capacity by August 2023.

Separately, D.22-05-015 authorized the use of non-bypassable customer charges to recover Modified Cost Allocation Mechanism (MCAM) costs from customers of LSEs that opt-out or do not comply with the RA adequacy requirements. Resolution E-5240 authorized SCE to complete transfers of its System Reliability Procurement Memorandum Account (SRPMA) balance and costs associated with D.22-05-016 are now recorded in its PABA, MCAMBA, and NSGBA, as of January 2023.

SCE estimated the 2023 year-end balance of its MCAMBA to be $990,000, including FF&U.

In opening comments on SCE's October Update, DACC noted that the MCAM revenue requirement increased 36 percent when compared to SCE's original application, but that SCE did not provide an adequate response to the significant increase in its forecast MCAM revenue requirement. Further, DACC noted that SCE did not update the 12-CP allocator, which is intended to allocate costs based on customers' contributions to each of the 12 monthly coincident peaks in a given year.[105] SCE addressed DACC's concerns in its Reply Brief stating that delaying implementation of the MCAM charges would shift the cost

[105] DACC Opening Comments at 1-3 and Data Request Set DACC-SCE-001, in which SCE noted "the amount for 2023 will change in both the October Update and in the subsequent implementation advice letter for the 2024 ERRA Forecast revenue requirement as SCE will replace the forecasts with actual recorded amounts."

of reliability resources SCE procured on behalf of other LSEs that opted out of reliability procurement to SCE's bundled service. However, SCE did agree to provide illustrative MCAM rates as part of its future ERRA proceeding applications going forward.[106]

6.3.4. Tree Mortality Contract Costs

SCE's tree mortality non-bypassable charge was applied to all procurement that has occurred pursuant to Resolution E-4770 and E-4805. As discussed in Section 5.2 above, SCE forecasted the fuel and purchased power costs that will be recorded in its TMNBCBA in 2024 to be -$4.581 million including FF&U.[107] SCE's forecasted BioRAM audit costs, which are also recorded in the TMNBCBA, are forecasted to total $18,000 in 2024.[108] In total, SCE estimates its TMNBCBA balance to reflect an undercollection of $10.588 million in 2023, including FF&U.[109] SCE also estimated that the balance of its BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA), which records the costs, energy, ancillary services revenue, RPS value, and RA value of BioMat contracts, to reflect an overcollection of $6.689 million as of December 31, 2023, including FF&U.[110]

6.3.5. Central Procurement Entity Related Costs

D.20-06-002 identifies SCE as the Central Procurement Entity (CPE) for its distribution service area and directs SCE to procure multi-year local RA contracts on behalf of all LSEs in its distribution service area beginning in 2023. As already

[106] SCE Reply Brief at 9-11.

[107] Exhibit SCE-06C at 118 and Table VIII-36.

[108] Exhibit SCE-06C at 118 and Table VIII-36.

[109] Exhibit SCE-06C at 119 and Table VIII-35.

[110] Exhibit SCE-06C at 119 and Table VIII-35.

noted, the CAM is the cost recovery mechanism for CPE procurement of local RA. SCE has a Centralized Local Procurement Balancing sub-account within its NSGBA BA to facilitate the cost recovery process.[111] SCE has several CPE-related procurement agreements entered into through separate CPE Local RA request for offers, spanning 2023 through 2026, each of which include CAISO costs under its scheduling coordinator identification number, SCE8.[112] The details of SCE's CPE-related contracts are confidential, pursuant to D.06-06-006.

Pursuant to D.22-03-034, SCE also forecasted $250,000 for 2024 administrative costs for utilizing independent evaluators to review its solicitation documentation for future CPE-related contracts, which was based on its most recent CPE solicitation evaluator costs.[113]

6.3.6. Discussion

No parties opposed SCE's proposed revenue requirement for New System Generation and System Reliability contracts, including those discussed in its CPE forecasted costs. We agree with DACC that SCE should provide more transparent information about the updated usage amounts in the 12-CP allocator presented in Advice Letter 4831-E/E-A proposed in its 2024 ERRA forecast in the Advice Letter implementing this proceeding.

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 NSGBA, reasonable and in compliance with applicable rules, orders and the Commission Decisions discussed above, and its requested revenue requirement is therefore authorized. SCE is directed to provide updated

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[111] D.20-06-002 OP 17 and Exhibit SCE-07C at 1.

[112] Exhibit SCE-07C at 3-7.

[113] Exhibit SCE-02C at 7, Exhibit SCE-07C at 8.

usage amounts associated with its MCAM charges when implementing this Decision.

6.4. Cost Responsibility Surcharges

The Cost Responsibility Surcharge (CRS) Indifference Amount is the difference between the total portfolio cost and the forecast value of the portfolio; it includes the Customer Transition Cost (CTC) and the Power Charge Indifference Adjustment (PCIA) charges.[114] SCE's CRS accounting also covered its Wildfire Fund Non-Bypassable Charge (NBC), which replaced the Department of Water Resources Bond Charge in 2020, in this portion of its 2024 ERRA forecast.[115] SCE noted that Track 4 of its 2021 GRC proceeding (A.19-08-013) could impact the PABA balance and any incremental recovery would be recovered through the CRS effective January 1, 2024, but the approved amount will not be known until a final Decision is adopted.[116] As of the date of this Decision, SCE's Track 4 2021 GRC proceeding has not been decided.

PCIA charges are discussed in Section 6.4.1, the CTC surcharge is discussed in Section 6.4.2, and the wildfire-related charges are addressed in Section 6.4.3, below.

6.4.1. PCIA

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 determined by the date of a customer's departure from bundled customer service. Customers who depart in the first half of each year are assigned to the

[114] 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.

[115] Exhibit SCE-01C at 123, Exhibit SCE-06C at 123, and Exhibit SCE-06C2 at124, Table IX-42.

[116] Exhibit SCE-01C at 136.

prior year's "vintage" and customers who depart in the second half of each year are assigned to the current year's "vintage."[117] SCE calculated its indifference amount for its 2024 PCIA by first estimating the above- and below-market costs of its portfolio, and then accounting for true-ups and adjustments in its portfolio balancing accounts. SCE forecasted that its generation portfolio is below market for 2024, resulting in an indifference amount of -$774.237 million which would result in a PCIA credit on most departed load customers' bills and lower electricity rates for SCE's bundled service customers.[118]

SCE's total 2024 PCIA revenue requirement forecast accounted 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 2022 PUBA undercollection in 2024; and (3) updates to SCE's revenue requirement in Track 4 of SCE's 2021 GRC proceeding, A.19-08-013.

In forecast year 2020, there was a cap on the year-over-year change in PCIA rates, pursuant to D.18-10-019. In D.21-05-030, however, the Commission removed the PCIA rate cap and trigger mechanism and 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).

For 2024, SCE calculated at total PCIA revenue requirement of -$218.219 million. The 2024 PCIA revenue requirement is illustrated in Table 6.4 and a list

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[117] For example, 2020 vintage departing load customers are those who departed SCE's bundled customer service between July 1, 2020, and June 30, 2021. SCE's vintages include 2001-2003, 2004-2008, and annually starting in 2009.

[118] *See* D.21-03-015.

of SCE's forecasted system average PCIA rates by vintage year is provided in Table 6-5.[119]

Table 6-4. Summary of SCE's 2024 ERRA Forecast Portfolio Costs, Portfolio Market Value, Balancing Account True-Ups, and Total PCIA Revenue Requirement[120]

PCIA Revenue Requirement	Amount (millions)
Portfolio Cost	$4,110.980
Market Value	-$4,884.941
• Energy Value	-$2,576.107
• RPS Value	-$860.117
• RA Value	-$1,448.717
One-Time Adjustments	-$380.0
Total 2024 Indifference Amount	-$774.341
Balancing Account True-Ups (no Uncollectibles Factor)	
• 2023 YE PABA Balance	-$609.487
• 2023 GRC Memo Account (27-Month Amortization)	-$14.415
• Remaining PUBA Balance to PABA	$2.948
• Emergency Reliability Utility-Owned Storage (UOS) Separator	$17.792
• 2023 YE ERRA Balance	-$59.297
2024 PCIA Revenue Requirement	-$217.826
2024 PCIA Revenue Requirement with Uncollectibles Factor	-$218.219

119 SCE's final revenue requirement and its associated PCIA rates will be updated in its Advice Letter implementing this Decision.

120 System average across customer classes. *See* October Update Appendix B and SCE-06CE3 Appendix B.

Table 6-5. PCIA Rates By Vintage

2001	0.00000
2004	0.00000
2009	0.00050
2010	0.00141
2011	0.00295
2012	0.00318
2013	0.00264
2014	(0.00354)
2015	(0.00663)
2016	(0.00901)
2017	(0.00855)
2018	(0.00996)
2019	(0.01240)
2020	(0.01949)
2021	(0.01533)
2022	0.00270
2023	(0.00065)
2024	(0.00065)

In opening testimony, CalCCA argued that SCE should provide a credit to Departing Load customers that paid for vintage 2018 and prior year RECs, if those pre-2019 banked RECs were to be used for SCE's RPS compliance for its bundled customers. CalCCA argued that these customers will have to pay for current and future RPS compliance in rates charged by their chosen LSE and should be compensated for RECs banked in or before 2018 if SCE uses them for RPS compliance for its bundled service customers.[121]

SCE addressed many of CalCCA's concerns in its rebuttal testimony filed on September 12, 2023. SCE argued that in each year, since the effective date of D.19-10-001, all Departing Load customers have received the market value of RECs banked in or after 2019 as revenue that was deducted from the PCIA on a customer vintage basis.

SCE further argued that D.18-10-019 and D.19-10-001 implemented changes to RECs banked on or after January 1, 2019, including any banked vintage 2018 RECs, and that its bundled customers have already collectively purchased and own the RECs banked prior to January 1, 2019, under the PCIA methodology in place prior to D.19-10-001. Therefore, SCE argued, its bundled customers should not have to pay for vintage 2018 or later banked RECs again, by providing a credit to Departing Load customers, when/if the pre-2019 RECs are subsequently retired for RPS compliance purposes.[122]

On September 11, 2023, SCE filed a Petition for Modification (PFM) of D.23-06-006 seeking clarity regarding the proper treatment and valuation of RECs that were banked prior to 2019, as the value relates to bundled and unbundled customers. The PFM is pending Commission action as of the date of this Decision.[123]

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[121] Exhibit CalCCA-01C at 8-16.

[122] Exhibit SCE-05C at 5-6.

[123] *See* Exhibit SCE-06CE3 at 136, footnote 161. "On October 11, 2023, PG&E, SDG&E and CalCCA submitted Responses to SCE's PFM. PG&E encourages resolution of the issues raised in SCE's PFM in the PCIA Rulemaking to avoid any inequitable outcomes in PCIA ratesetting amongst the IOUs. SDG&E states that for the reasons set forth by SCE and as discussed in its Response, the PFM should be granted. CalCCA states that the Commission should deny SCE's PFM. On October 11, 2023, SCE requested permission to file a reply."

We agree with SCE that the Commission has not, to this date, found that SCE's bundled service customers owe additional credits to Departing Load customers when SCE uses RECs banked in or before 2018.[124] However, upon review of SCE's October Update and CalCCA's concurrent opening comments and briefs related to the valuations of pre-2019 banked RECs, and upon consideration of the open PFM filed in Rulemaking 17-06-026, we find CalCCA's proposal to continue the interim process adopted in D.22-12-012, as it relates to the use of banked RECs, to be reasonable.

D.22-12-012 directed SCE to use RECs banked in or after 2019 for compliance before using any RECs banked in, or prior to, 2018 and found it to be a reasonable interim solution to this contested issue. We therefore direct SCE to utilize all available banked RECs generated in 2018 or later first, to minimize the potential impact of the use of RECs banked before 2019 on Departing Load customers. Further, we direct SCE to continue to apply this interim process until or unless a decision is reached on the PFM.

SCE shall update its PCIA forecast for 2024 to adhere to the interim process described above for the treatment of banked RECs. We also identify that the current scope of SCE's PFM to D.23-06-006 focuses on the valuation of RECs banked in or before 2018, so we do not address this contested issue here, beyond the directive assigned for SCE's 2024 ERRA Forecast implementation and its next ERRA Forecast application. Discussion on the valuation of RECs banked prior to

[124] D.22-012-012 at 60-61.

2019, if deemed necessary for SCE's bundled customer 2024 RPS compliance, is included in Section 6.5 below.[125]

CalCCA separately stated SCE's inclusion of negative generation from energy storage systems in the PCIA "acts as an additional portfolio cost… because it reduces the total portfolio generation output to which the Energy Index MPB is applied; and, therefore, reduces the market value of energy in the Indifference Account."[126] CalCCA suggested that SCE's inclusion of the cost of purchasing energy to charge its energy storage resources and the negative generation from energy storage systems results in double-counting of nearly half of the storage costs in its Indifference Account.[127]

CalCCA also noted that SCE included an adjustment in its PCIA workpapers that reduces RA attributes at solar facilities where newly installed energy storage resources have been added pursuant to D.19-11-016. CalCCA referenced SCE's Advice Letter 4218-E, which stated "because cost responsibility for the Existing RPS PPAs is via the PABA and not Modified CAM (meaning some customers are responsible for the existing solar projects via the PABA but are not responsible for the co-located energy storage projects due to their LSE electing to self-procure pursuant to D.19-11-016), it is necessary to credit the PABA by applying a corresponding debit entry to the Modified CAM account to

[125] In its November 17, 2023, Opening Comments on the Proposed Decision, SCE noted that this directive will result in an update to its 2024 F&PP forecast. SCE proposed to address this update in the Tier 1 advice letter implementing this Decision as discussed in Ordering Paragraph 10 below.

[126] Exhibit CalCCA-02C at 20-22.

[127] Exhibit CalCCA-02C at 22-23.

prevent cost-shifting if a change in value results in the existing solar projects from co-locating the energy storage projects."[128]

In its rebuttal testimony, SCE noted that the key difference between its revised methodology and CalCCA's proposed methodology is the forecasted "price" of discharging battery-stored energy. In Exhibit SCE-05C (at 9-10), SCE described how its original methodology for valuing energy storage contract costs had "imperfections" and then provided an updated methodology that separated the charging cost from the discharging value, which applied the lower off-peak price to forecast the charging costs and the Energy Index MPB to forecast the value of discharging the battery. In its opening brief and its reply comments on the Proposed Decision, SCE explained that its proposed methodology uses a total portfolio approach to determine the costs, market value, and above market costs of SCE's PCIA-eligible portfolio.[129] In its opening comments to the PD, CalCCA argued that the portfolio approach proposed by SCE would result in market value being forecasted differently for different PCIA-eligible technologies, but it concurred that CAISO may call upon energy storage resources at times other than peak hours.[130] Upon review of SCE's testimony and Opening and Reply Comments and Briefs to SCE's October Update, we find SCE's updated methodology to be reasonable and in line with the PCIA methodology. We agree

[128] Exhibit CalCCA-02C at 25 and SCE Advice Letter 4218-E at 31-32.

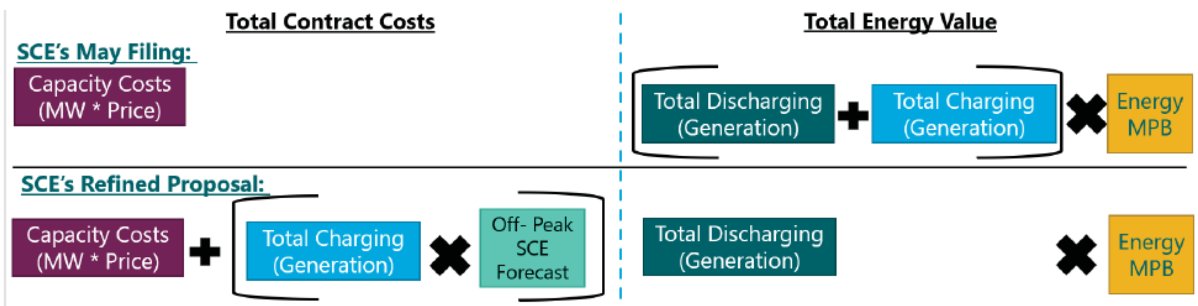
[129] *See* SCE's opening brief at 5-6 and reply comments at 3: "[I]n SCE's 2023 ERRA Forecast, the Commission approved a valuation that included negative generation in the forecast energy market valuation at the Energy Index MPB in addition to portfolio costs that were net of SCE's forecasted market revenues. The negative generation was the sum of the total hours of the energy storage facility's charging and discharging – a negative number because the forecasted charging hours exceeded discharging hours. Because the sum was negative, the forecast market value (at the Energy Index) was also negative and so acted like a cost input to the Indifferent Amount calculation (even though it was on the "Market Value" side of the calculation)."

[130] CalCCA opening comments on the PD at 2 and 7.

that the discharging price should not, on the whole, be valued at SCE's on-peak pricing costs, because the resource could be called upon at other times of the day. We also agree that charging batteries during off-peak hours should be encouraged and find the use of off-peak pricing for battery charging in SCE's 2024 ERRA Forecast to be reasonable. Therefore, we adopt SCE's proposal to use its updated methodology as illustrated by the bottom row of the diagram below:

Figure 6.4.1-1[131]

Comparison of Energy Storage Contract Costs and Energy Value Calculations



6.4.2. Customer Transition Cost Surcharge

The Customer Transition Cost (CTC) Surcharge recovers all above-market costs associated with contracts previously necessary to serve departing customers, regardless of their date of departure from investor-owned utility generation service. For 2024, SCE's October Update and its associated errata forecasted the following average CTC costs: (1) $0.00020/kWh for Domestic (D); (2) $0.00019/kWh for Street Lighting customers; (3) $0.00015/kWh for TOU-GS-1, TC-1, TOU-GS-2, and TOU-GS-2; $0.00014/kWh for TOU-8-Sec and TOU-8-Pri; $0.00015/kWh for TOU-PA-2, TOU-PA-3, and Standby-Sec;

131 Exhibit SCE-05C at 8.

(4) $0.0014/kWh for Standby-Pri customers; and $0.00013/kWh for TOU-8-Sub and Standby-Sub customers of all vintages.[132]

6.4.3. Wildfire Fund Non-Bypassable Charge

The Wildfire Fund Non-Bypassable Charge (WF NBC) helps fund the Wildfire Fund, which is an insurance fund that allows recovery of prudently incurred utility wildfire costs and provides financial security to California's electrical corporations. Each year, the Commission adopts a rate for the WF NBC to be collected by the IOUs from eligible customers to fund an annual revenue requirement for the statewide Wildfire Fund of $902.4 million. For 2023, SCE's WF NBC is $0.00530/kWh. For 2024, SCE estimated that the cost recovered from all customer classes for the WF NBC to be $0.00561/kWh. SCE noted that it will update the WF NBC in its PCIA workpapers as part of the January 1, 2024, consolidated revenue requirement and rate change that is anticipated to be approved within R.23-03-007 by the Commission in December 2023.[133]

No parties directly addressed SCE's forecasted 2024 Wildfire Fund NBC costs, and upon review of SCE's testimony and the annual allocation of each IOU's contribution, we find the forecasted costs to be reasonable and in line with state and Commission regulatory requirements, and thereby approve them.

6.5. Renewables Portfolio Standard Value and the Voluntary Allocation Market Offer Process

SCE included forecasts of its PCIA and non-PCIA eligible renewable energy certificates (RECs) using a three-step process: (1) calculating the RECs elected by parties during the Voluntary Allocation Market Offer (VAMO) Process adopted in D.21-05-030; (2) assuming all unallocated RECs are offered

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[132] Exhibit SCE-06CE2 Appendix B.

[133] Exhibit SCE-06C at 136.

via the Market Offer Process; and (3) evaluating SCE's Renewables Portfolio Standard (RPS) compliance needs to determine which (if any) RECs would be used from SCE's bank. While SCE's total portfolio includes non-PCIA eligible RECs, its 2024 forecast considered the VAMO process. SCE completed its short-term Market Offer solicitation prior to its initial ERRA filing and stated that it received higher contract prices through its long-term Market Offer solicitation in its October Update.[134]

SCE also estimated that it may need to use banked RECs for some portion of its 2024 RPS requirements. SCE therefore forecasted the value of pre-2019 banked RECs that may be necessary for 2024 RPS compliance and subtracted that from the RPS portion of its PABA portfolio.[135]

CalCCA noted that only SCE's 2024 bundled customers should be responsible to recover any costs of SCE's RPS compliance in 2024, as the CCAs are also required to comply with the RPS, and their customers must bear the cost of the CCAs' compliance. CalCCA argued that it is "unfair to count RECs generated in prior years and paid for by now-departed customers toward RPS compliance for current bundled customers."[136] It provided similar testimony in SCE's 2023 ERRA Forecast proceeding and requested that a permanent methodology be adopted in the PCIA proceeding.[137]

As addressed in section 6.4.1 above, D.23-06-006 confirmed that IOUs should apply the MPB for the year in which they use the banked REC, pursuant

[134] Exhibit SCE-06C at 7 and 23.

[135] Exhibit SCE-01C at 132 and Exhibit SCE-06C at 130-131.

[136] Exhibit CalCCA-01C at 11.

[137] SoCal CCAs Opening Brief in A.22-05-014 at 18-19 and D.22-12-012 at 60.

to D.19-10-001, which addresses RECs procured and banked after vintage 2018.[138] CalCCA argued that D.23-06-006 did not address the outstanding issue of how Departing Load customers should be credited for the value of RECs that were procured and banked prior to 2019 that are used for SCE's RPS compliance in future years. CalCCA suggested the difference between the MPB for the year in which bank RECs are used and the value of the REC in the year they were generated should be credited to the PCIA vintage customer class(es) that were SCE customers in the year in which the banked RECs were generated.[139] CalCCA further stated that an offsetting charge on SCE's bundled customers could make up the cost of providing the credit to departed load customers.

In its protest, Cal Advocate's position aligned with CalCCA's. Cal Advocates stated that D.23-06-006 closed the PCIA proceeding without addressing the issue of how to value RECs banked in or before 2018. However, Cal Advocates argued that the "determination of the values for banked RECs should be applied uniformly across all IOUs and not determined in a single IOU ERRA forecast application, which may lead to inconsistencies in how different IOUs account for the values in their PABA accounting."[140]

On September 20, 2023, CalCCA and SCE stipulated that evidentiary hearings are not necessary on this issue and provided additional exhibits illustrating how treatment of banked RECs occurred in PG&E's 2024 ERRA

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[138] D.23-06-006 at 44.

[139] Exhibit CalCCA-01C at 11-18.

[140] Cal Advocates protest at 3-4.

Forecast testimony. PG&E proposed to use a "last-in, first out" approach to retire banked RECs,[141] whereas SCE proposed to use a "first-in, first out" approach.[142]

In opening comments and opening briefs to SCE's October Update testimony, CalCCA and SCE both noted the banked REC valuation issues raised in briefs are still in dispute.[143]

CalCCA and Cal Advocates' concerns about the treatment of banked RECs are discussed in more detail in Section 6.4.1 above. SCE is directed to update its 2024 ERRA forecast pertaining to its banked REC value to align with the interim process adopted in D.22-12-012 which ensures that RECs SCE banked in or after 2019 be used first for its bundled service RPS compliance. Should SCE determine that the use of RECs banked in or before 2018 is necessary for its bundled service RPS compliance, it should value those RECs at zero, as it proposed.[144] We further agree with Cal Advocates that the issue of the valuation of RECs banked in or before 2018 would not be appropriately addressed in a single IOU's annual ERRA forecast application proceeding. This Decision adopts an interim solution and authorizes SCE to make modifications necessary to implement the interim solution in 2024. The issues raised in SCE's PFM to D.23-06-006 are therefore not addressed in this proceeding.

7. Greenhouse Gas Forecast Costs, Revenues, and Reconciliation

In D.14-10-033, the Commission adopted standard procedures for electric utilities to request greenhouse gas (GHG) forecast revenue and reconciliation

[141] Exhibit CalCCA-04 at 9-20 through 9-24.

[142] Exhibit SCE-01C at 132.

[143] SCE Opening Comments and Opening Brief at 10-15; CalCCA Opening Comments and Opening Brief at 7-14.

[144] SCE Opening Brief at 9 and Reply Brief at 8-9.

requirements filed after 2013; adopted Confidentiality Protocols for Cap-and-Trade-related data; and required the utilities to use a proxy price in their forecasts. The IOUs were also required to submit GHG Forecast Revenue and Reconciliation Applications annually within their ERRA forecast filings.[145] In Advice Letter 4587, SCE submitted updated GHG templates (Templates D-1 through D-5), as directed by D.21-08-026.[146] We therefore apply the standards adopted in D.21-08-026 to review SCE's current forecast and determine the reasonableness of its revenue and reconciliation proposal.

7.1. Greenhouse Gas Costs

SCE and the other IOUs in California began incurring compliance costs related to Assembly Bill 32 and the California Air Resources Board's (CARB) GHG cap-and-trade program in January 2013. The program is intended to reduce California's economy-wide GHG emissions to 40 percent below 1990 levels by 2030. Because SCE still owns, operates, and procures power from GHG-emitting resources, it incurs compliance costs associated with this program either directly or indirectly.

Direct GHG costs are related to GHG-emitting resources from which SCE is the 'first deliverer' of electricity, such as in-state facilities that emit 25,000 metric ton (MT) of GHG or out-of-state facilities that exceed an emissions rate of 0.428MT/MWh.[147] Based on CARB's calculations of SCE's resource portfolio,

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[145] D.14-10-033 was modified by D.15-01.024 and D.15-07-001. 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."

[146] *See* D.21-08-026 at 3 and Ordering Paragraph 12.

[147] GHG emissions are measured in carbon dioxide equivalent (CO_2e).

SCE must procure and surrender compliance instruments to CARB on annual and triennial deadlines.

SCE is also exposed to indirect GHG costs through its QF contracts and its wholesale market electricity purchases, each of which include an embedded GHG compliance price.

For 2024, SCE forecasted a proxy price of $39.36/MT of GHG emissions, using the Intercontinental Exchange (ICE) settlement price for the December delivery of a 2024 vintage GHG allowance. SCE forecasted $461.506 million in costs resulting from compliance with the California Cap-and-Trade program in 2024 across its direct and indirect costs, GHG costs associated with its QF contracts, and GHG costs associated with electricity purchased from the California wholesale market.[148]

SCE estimated its 2024 GHG allowance revenue would total $942.533 million, as illustrated in Table 7-1.[149],[150]

[148] Exhibit SCE-06CE2 at 60-63.

[149] Exhibit SCE-06C at Table VII-33.

[150] Exhibit SCE-01C at 70, Exhibit SCE-06C at 83-84, and Exhibit SCE-06CE2 at Table VII-33.

Table 7-1. Summary of SCE 2024 GHG Allocated Allowance Auction Proceeds and Related Expenses[151]

Program	SCE Proposed (Millions)
GHG auction revenues	
1. 2023 GHG Auction revenue true-up	-$45.488
2. 2024 Forecast GHG auction allowance revenues	-$9321.108
3. 2024 Forecast FF&U	-$10.425
GHG Revenue Subtotal	**-$998.021**
Administrative Expenses	
1. 2024 Outreach and Administrative Expenses	$0.325
2. 2024 Forecast FF&U	$0.004
Subtotal	**$0.329**
Clean Energy and Energy Efficiency Programs	
1. SCE 2024 Solar on Multifamily Affordable Housing Program (SOMAH)	
2. SCE 2023 SOMAH True-Up	$46.528
3. SCE 2024 Disadvantaged Communities — Single-family Solar Homes (DAC-SASH)	-$18.592
4. SCE 2024 Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT)	$4.600
5. CPA 2024 DAC-GT and CSGT	$0
6. Cal Choice 2024 DAC-GT and CSGT	$0.27
7. 2024 SCE Clean Energy Optimization Pilot (CEOP)	$0.25
	$0

[151] Exhibit SCE-06CE2 at 94, Table VII-33.

Program	SCE Proposed (Millions)
Total Clean Energy and EE Program Set-Asides	**$32.587**
Total GHG Allowance Returns 1. 2024 EITE Customer Return 2. 2024 California Climate Credit[152]	 -$58.834 -$896.271
Net GHG Revenues Available for Return	**-$955.105**

As noted above, SCE forecasted that this would provide its residential and small commercial customers with a California Climate Credit Amount of $86.00 in April and October 2024.[153]

SCE proposed to allocate direct GHG costs to the customers who receive a benefit from the resources to which the GHG costs are attributable, and to include the direct cost of the GHG compliance instruments in its proposed generation service though the ERRA BA, PABA and the ESMA, as described in Exhibit SCE-01C Table IV-19.[154]

7.2. Greenhouse Gas Forecast Revenues and Reconciliation

SCE proposed to return $896.271 million in GHG revenue in its residential and small commercial customers' 2024 California Climate Credit.[155] This estimate accounted for administrative and customer outreach costs and would equal

[152] Exhibit SCE-06CE2 at Table VII-33. SCE estimated there will be 5,227,178 households and small business customers eligible for its 2024 California Climate Credits.

[153] Exhibit SCE-01C at 72-73; 83-86; and Table IV-20 and Exhibit SCE-06C at 92.

[154] Exhibit SCE-01C at 65-71 and Table IV-19.

[155] Exhibit SCE-01C at 72-73; 83-86; and Table IV-20 and SCE-06C Table VII-33.

$86.00 per eligible customer in bill credits forecasted to be distributed in April and October 2024.

SCE separately proposed to return $58.834 million to its EITE Customers, as discussed further in Section 8.4 below.[156]

7.2.1. Greenhouse Gas Allowance Balancing Account True-Up

As of October 2023, SCE estimated its GHG allowance proceeds will result in an overcollection of $45.488 million in 2023. This represents the consignment to auction of GHG allowances allocated to SCE by the State of California, which were consigned to auction in 2023.

7.2.2. Administrative and Customer Outreach Expenses

SCE forecasted it will spend approximately $0.325 million to administer its California Climate Credit program in 2024, which includes internal employee and customer-outreach related costs. The majority of administrative costs are associated with the disbursement of the California Climate Credit in April and October, and SCE's 2024 forecast aligns with what was approved in D.22-12-012 in its 2023 ERRA forecast proceeding.[157] No parties opposed or commented on SCE's 2023 forecast of administrative and customer outreach expenses. Upon consideration, the Commission finds SCE's 2024 forecast GHG-revenue related administrative and customer outreach expense costs reasonable and in compliance with applicable rules, orders, and Commission Decisions.

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[156] Exhibit SCE-01C at Table VII-34 and Exhibit SCE-06C at Table VII-33.

[157] Exhibit SCE-01C at 87-88.

7.2.3. Historical Allowance Receipts and Customer Returns

SCE forecasted an over-disbursement in 2023 due to a difference between its previously forecasted and actual allocated allowance auction proceeds and returns. In its 2024 ERRA forecast, SCE forecasted a $45.488 million overcollection in 2023 allocated allowance auction proceeds from its projected 2024 forecasted allocated allowance auction proceeds. The total California Climate Credit available in April and October 2024 to residential and small commercial customers will be $86.00 per eligible customer, up from $71 in 2023.

7.3. Discussion

No party directly addressed SCE's forecasted GHG costs, forecasted allocated allowance auction proceeds, or other aspects related to SCE's GHG accounting for its 2024 ERRA forecast proceeding. Upon review of SCE's testimony, October Update, and associated workpapers, we find they are in compliance with existing state law, Commission rules, orders, and prior Decisions and are therefore approved.

8. Clean Energy Programs Funding

Pub. Util. Code § 748.5(c) authorizes the Commission to allocate up to 15 percent 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 not funded by any other source and are already approved by the Commission. SCE noted that it has set aside $32.587 million in allowance revenues to fund all of its Clean Energy Programs in 2024.[158]

[158] Exhibit SCE-01C at 85-86, and Exhibit SCE-06C at 85, footnote 77.

8.1. Solar on Multifamily Affordable Housing Program

Assembly Bill 693 (Eggman), Statutes of 2015, Chapter 582 created the Solar on Multifamily Affordable Housing (SOMAH) program, allocating 10 percent of GHG allowance auction proceeds, or up to $100 million annually, whichever is less, for fiscal years 2016 through 2026. Under SOMAH, all IOUs, including small/multijurisdictional utilities, that are regulated by the Commission must use a share of GHG allowance auction proceeds to install solar photovoltaic systems on multifamily affordable housing throughout California.[159] SCE began setting aside funding for SOMAH in 2017, and the SOMAH program began operating on July 1, 2019. In D.17-12-022, the Commission required that 10 percent 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.[160]

D.20-01-022 clarified that prior-year GHG revenue allocations should be trued-up based on a 10 percent allocation of actual GHG revenues received. In D.20-04-012, the Commission extended SOMAH through June 2026, clarified existing requirements, and set additional requirements for the SOMAH budget true-up process.[161] D.22-09-009 modified the forecast budgeting process by adding a pathway for each IOU to request to set aside its proportionate share of a $100 million budget and identifying a set allocation for each IOU's share.[162] This

[159] D.17-12-022.

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

[161] 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 2023.

[162] D.22-09-009 Table 1.

pathway is dependent on their ability to adequately demonstrate that the IOUs' combined forecast GHG allowances will equal or exceed $1 billion.[163] As a result, IOUs may either propose setting aside 10 percent of their forecast revenue or their share of $100 million.

In its 2024 ERRA forecast, SCE set aside $46.528 million to cover its share of the $100 million annual SOMAH cap. It also noted that its 2022 SOMAH true-up, which will be recorded in 2023, would result in a decrease in SOMAH funding of $18,592,218.[164]

No parties commented on SCE's proposed SOMAH allocation. Upon review, the Commission finds SCE's SOMAH allocation reasonable and in compliance with applicable rules, orders and Commission Decisions. A summary of SCE's SOMAH forecasted allocation for 2024 is detailed below.

Table 8-2. Table of IOU Proposed PY2024 GHG Revenue Reallocation to Account for SOMAH Program $100 Million Annual Amount[165]

PY	2024 Forecast GHG Proceeds ($000)	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	$663,932	39.75737884%	$39,757,378.84
SCE	$932,108	46.52785609%	$46,527,856.09
SDG&E	$246,235	12.01597192%	$12,015,971.92
PacifiCorp	$16,897	1.29882216%	$1,298,822.16
Liberty	$5,309	0.39997099%	$399,970.99
IOU Sum	**$1,864,481**	100.000%	$100,000,000

163 D.22-09-009 OP 3.

164 Exhibit SCE-06C at 88. *See* Advice Letter 4978-E-A, filed pursuant to OP 4 of D.22-09-009.

165 Exhibit SCE-06CE3, Table VII-31.

Table 8-3. Table Summarizing the PY2023 SOMAH Program True-Up[166]

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[167]	$551,751,564	$49,498,366	$63,966,285	-$14,467,919
2022	$700,179,282	$50,134,994	$ 73,364,564	-$23,229,570
Total	**$3,056,364,207**	**$280,076,697**	**$298,668,914**	**-$18,592,218**

8.2. Disadvantaged Community Programs

8.2.1. SCE's Disadvantaged Community Programs

In D.18-06-027, the Commission created the Disadvantaged Communities (DAC) Single Family Solar Homes (SASH) program and set an annual $10 million budget. SCE's proportionate share of that $10 million annual budget is 46 percent, starting in 2019. In its 2024 ERRA Forecast, SCE has allocated $4.6 million to its DAC-SASH program (46 percent of $10 million).[168]

On April 3, 2023, SCE submitted Advice Letter 5002-E requesting to spend $8.377 million on its DAC Green Tariff (DAC-GT) and Community Solar Green Tariff (CSGT) Programs. However, because SCE had already set aside

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[166] *Id.* Table VII-32 at 86 and Exhibit SCE-06C at 89, Table VII-32.

[167] 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.

[168] Exhibit SCE-06 at 90 and Table VII-34.

$5.360 million through 2022 for above-market costs, the need through 2023 was only
$1.108 million. SCE did not request any additional GHG funding for its DAC-GT or CSGT programs, because the projected $709,000 in program costs are expected to be covered through public purpose program (PPP) funds.[169] Accordingly, SCE's proposed to recover only $709,000 for its DAC-GT and CSGT proposed to be funded through its PPP funds in 2024, and does not expect to expend any additional GHG allowance revenues in 2024 for this DAC program.[170]

8.2.2. Community Choice Aggregator DAC Programs

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. Clean Power Alliance of Southern California (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.[171]

The volumetric limits on GHG funding also apply to CCA programs, and SCE noted that only the above-market generation portion of the CCA program funding requests will be funded through GHG allowance revenue.

Through Advice Letter 0021-E-A, CPA requested a total of $3.569 million for its DAC-GT and CSGT programs in 2024. Combined with CPA's 2021 corrections of $8,000 and unspent 2022 funding of $1.940 million, CPA's requested net funding was $1.649 million. Given the limits on GHG funding for

[169] Exhibit SCE-01C at 88-93, as updated by Exhibit SCE-06CE2 at 90.

[170] Exhibit SCE-06C at 90-91 and Table VIII-36, as updated by Exhibit SCE-06CE2 at 90-91.

[171] Exhibit SCE-01C at 93.

volumetric rebates, however, only the above-market generation portion of $26,769 will be funded through SCE's GHG allowance revenue. The remaining $1.630 million will be recovered through PPP funds. .[172]

The Joint CCAs filed an advice letter on April 3, 2023, seeking 2024 GHG funding for their DAC-GT and CSGT programs of $370,000. Similar to CPA, the Joint CCAs had a 2022 budget carryover of $147,000, which resulted in a net funding request of $229,000.[173] The generation-related GHG funding portion was $25,029, and the remaining $204,000 was proposed to be recovered through PPP rates.[174]

No parties commented on SCE's set aside for its own or the CCA's DAC programs. Upon consideration, the Commission finds SCE's 2024 forecast for DAC-SASH, DAC-GT and CSGT set-asides to be reasonable and in compliance with all rules, law and Commission orders.

8.3. Clean Energy Optimization Pilot

In D.19-04-010, the Commission approved a $20.4 million Clean Energy Optimization Pilot (CEOP) designed to provide a pay-for-performance pilot project at University of California (UC) and California State University (CSU) schools, starting in 2019. D.20-01-002 authorized SCE to spend $10 million for the CEOP. Due to the COVID-19 pandemic, UC and CSU schools transitioned to remote learning, drastically affecting on-campus energy use. As a result, a Petition to Modify (PFM) D.19-04-014 was filed in August 2020. D.20-12-035

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[172] Exhibit SCE-01C at 93, Exhibit SCE-06C at 91-92 and Table VII-34, and Exhibit SCE-06CE2 at 91.

[173] Exhibit SCE-06CE2 at 91-92.

[174] Exhibit SCE-01C at 93-94 and Exhibit SCE-06C at 92 and Table VII-34.

approved a settlement agreement that modified the CEOP and authorized it to continue.[175]

D.22-01-003 separately authorized an additional $10 million to fund CEOP. Because SCE already requested and attained approval for funding totaling $20.4 million for the project, it forecasted that, as of 2023, its CEOP program is fully funded and did not request any further funding in the instant application.[176]

No parties commented on SCE's CEOP funding in this proceeding. Upon review, SCE's request is consistent with all rules, law and Commission orders, and no additional funding for the CEOP program is granted in this Decision.

8.4. Emissions-Intensive and Trade-Exposed Customer Return

Customers operating emissions-intensive and trade-exposed (EITE) businesses are eligible to receive industry assistance in the form of a bill credit once annually, in April. SCE forecasted its 2024 EITE customer return costs to be $58.834 million. No party commented on SCE's forecasted EITE costs for 2024, and upon review, the Commission finds them consistent with all rules, laws, and prior Commission orders. SCE is authorized to return the $58.834 million allocated to industry assistance funds to eligible EITE customers in 2024, as proposed in its testimony, workpapers, and October Update documents.

9. Cost Responsibility Surcharge

9.1. 2024 Cost Responsibility Surcharges

SCE described the methodology and updated inputs used to determine the 2024 Indifference Amount, which goes into bundled service customers'

175 D.20-12-035 at 39.

176 Exhibit SCE-01C at 94 and Exhibit SCE-06C at Table VII-33.

generation rates and recovered from departing load customers through the CTC and PCIA rates as discussed in Section 6.4 above.[177]

In its October Update, SCE noted that its forecasted 2024 Indifference Amount decreased primarily as a result of applying the updated MPBs provided on October 2, 2023, by the Commission's Energy Division.[178]

Table 9-1. Comparison of Forecast PCIA Market Price Benchmarks[179]

MPB	2024 ERRA Forecast (June Submittal)	2024 ERRA Forecast (October Update)	Percent Change
Energy Index	$71.87/MWh	$61.50/MWh	-14.43%
RPS Adder	$12.63/MWh	$31.73/MWh	151.23%
RA System Adder	$88.68/kW-yr	$182.76/kW-yr	106.09%
RA Local Adder	$80.88/kW-yr	$105.72/kW-yr	30.71%
RA Flexible Adder	$85.80/kW-yr	$109.44/kW-yr	27.55%

SCE's forecasted decrease in its Indifference Amount is offset somewhat by an increase in the forecasted undercollection in SCE's ERRA BA at the end of 2023, which is largely due to the application of the 2023 Final RPS and RA Adders, as discussed further in Section 9.2 below.[180]

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177 The Cost Responsibility Surcharge tariff that applies to departing load customers includes the CTC, PCIA, and the Wildfire Fund NBC discussed in Section 6.4.3 above.

178 Exhibit SCE-06CE2 at 122.

179 Exhibit SCE-06CE2 at 126-127 and Table IX-43.

180 Exhibit SCE-06CE2 at 122.

SCE noted that its updated energy value was about 13 percent lower, due to the updated energy index identified in Table 9-1 and the application of the new weighting methodology adopted in D.23-06-006.[181] SCE's forecasted RA Value increased by approximately 51 percent, and its forecasted RPS value increased by approximately 104 percent, compared to its June testimony. The increase in RA and RPS Values were driven by the increased MPBs identified in Table 9-1.

SCE noted that it will make any adjustments to its PCIA Indifference Amount calculations, if necessary, due to any potential Commission action on its PFM of D.23-06-006.[182]

9.2. 2023 Cost Responsibility Surcharge True-Up

Pursuant to D.18-10-019 and D.19-10-001, SCE conducted an annual true-up of its PCIA and CTC rates to reflect the actual values realized in market transactions related to its PABA portfolio's energy value.[183] D.19-10-010 adopted specific methodologies for the Energy Division to provide final RPS and RA adders, and D.22-01-023 moved the timeframe for the Commission's Energy Division to release final RPS and RA to the first business day of October each year.[184]

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[181] Exhibit SCE-04CE at 3-5. In Exhibit SCE-06CE2 at 127, SCE noted that it did not make changes to its filing that was submitted pursuant to Ordering Paragraph 6 of D.23-06-006 in its October Update or its associated errata.

[182] Exhibit SCE-06CE2 at 130-132. For all other Actual Retained RPS related value, SCE is applying the RPS Adder in calculating its Indifference Amount.

[183] SCE implemented D.18-10-019 through Advice Letter 3914-E, which was approved by the Commission's Energy Division with a January 9, 2019, effective date. SCE records actual retained RPS and RA values as credits in its PABA, which correspond with debit entries in its ERRA BA along with other applicable cost-recovery accounts for those RPS and RA resources. *See* Exhibit SCE-06C at 139 and Exhibit SCE-06CE2 at 139.

[184] D.22-01-023 OP 1.

The following table provides SCE's comparison of 2023 forecast MPBs to 2023 final MPBs, which were issued by the Energy Division in October 2023.

Table 9-2. Comparison of 2023 Forecast MPBs to 2023 Final MBPs[185]

Market Price Benchmark (MPB)	2023 Forecast Adders (In Rates)	2023 Final Adders (October 2023)	Percent Change
Energy Index	$81.17/MWh	N/A (use actuals)	N/A
RPS Adder	$12.63/MWh	$30.30/MWh	140%
RA System Adder	$88.68/kW-yr	$172.44/kW-yr	94%
RA Local Adder	$80.88/kW-yr	$93.48/kW-yr	16%
RA Flex Adder	$85.80/kW-yr	$93.84/kW-yr	9%

As discussed in Section 6.1.2 above, SCE records the differences between actual above-market costs and actual customer revenues in its PABA. With the updated MPBs, the forecast 2023 year-end PABA balance is $609.487 million, or $616.304 million when including the gross-up for Uncollectibles.

SCE noted that the 2023 undercollection in its PABA account was largely due to a "much larger-than-forecast 2022 year-end balance in the ERRA BA," which was a total of $1.582 billion.[186] SCE's forecasted customer rates were therefore too low and a key driver of the PABA undercollection. SCE also noted lower-than-forecast energy revenues as a key driver of its PABA undercollection, along with a 41 percent decrease in CAISO market revenues.[187]

SCE's projected 2023 year-end RPS Value, however, is forecasted to be approximately 97 percent higher than its forecasted RPS Value, given the

[185] Exhibit SCE-06C at 140-141 and Table X-49.

[186] Exhibit SCE-06C at 144.

[187] Exhibit SCE-06CE2 at 144.

significantly higher Final RPS Adder described in Table 9-1 above.[188] Similarly, SCE's projected 2023 year-end RA Value is estimated to be approximately 78 percent higher than forecast.[189]

10. SCE's 2024 ERRA Forecast Class Average Rates

Pursuant to D.22-08-023, SCE included the affordability metrics associated with its 2024 ERRA Forecast, which results in a decrease to SCE's currently authorized revenues.[190] Table 10-1 below provides SCE's updated 2024 ERRA Forecast Class Average Rates, as updated in the October Update and its associated errata.[191]

[188] Exhibit SCE-06C at 146-147.

[189] Exhibit SCE-06C at 148-149.

[190] SCE noted that because its 2024 ERRA forecast will result in a decrease to its currently authorized revenues, it is not required to introduce Affordability Ratio 20 by climate zone, Affordability Ratio 50 by climate zone, or Hours-at-Minimum-Wage. *See* Exhibit SCE-06C at 151 and D.22-08-023 at OP5.

[191] Exhibit SCE-06CE2 at 152 and Table XII-55.

Table 10-1. SCE's 2024 ERRA Forecast Class Average Rate Changes

Rate Schedule		**Percent Change**	**Total $/kWh**
Domestic	**Average**	**-5.0**	**0.28989**
	D	-3.9	0.32949
	D-CARE	-6.4	0.20417
	DE	-4.7	0.24794
	DM	-6.3	0.20755
	DMS-1	-0.7	0.34457
	DMS-2	-0.8	0.34441
Lighting- Small/Med Power	**Average**	**-0.6**	**0.28717**
	GS-1	-3.0	0.28169
	GS-2	3.0	0.30968
	TC-1	2.7	0.33160
	TOU-GS	-4.8	0.25211
Large Power	**Average**	**-3.6**	**0.19268**
	TOU-8-S	-2.6	0.22851
	TOU-8-P	-1.1	0.21338
	TOU-8-T	-6.8	0.13714
	TOU-8-S-S	-3.0	0.24094
	TOU-8-S-P	-2.0	0.23388
	TOU-8-T	-4.6	0.15106
Agricultural & Pumping	**Average**	**-6.1**	**0.23072**
	TOU-PA-2	-9.3	0.24990
	TOU-PA-3	-2.7	0.20864
Street & Area Lighting	**Average**	**-6.3**	**0.30606**
	LS-1	1.3	0.51749
	LS-2	1.1	0.27389
	LS-3	-4.7	0.16202
	DTL	1.0	0.51226
	OL-1	0.7	0.41796
Average Across Customer Groups		**-1.8**	**0.26124**

11. Fixed Generation Costs

As discussed in Section 1 above, the ALJ issued a Ruling on August 1, 2023, seeking party input on how to address issues related to fixed generation costs. The same Ruling was sent to parties involved in PG&E's 2024 ERRA forecast (A. 23-05-012) and SDG&E's 2024 ERRA forecast (A.23-05-013). We find it reasonable to consider the opening and reply comments filed in all three proceedings when conducting our evaluation of these issues in the instant case.

The Ruling specifically asked parties to:

1. Identify and briefly describe each category of Fixed Generation Costs in the 2024 ERRA proceeding(s).
2. Complete a table identifying where fixed costs are currently tracked, the estimated cost for each cost category for 2023, and the estimated 2023 cost for a "hypothetical last remaining bundled customer."[192]
3. Describe any issues associated with Fixed Generation Costs that should be addressed in the 2024 ERRA proceeding(s).
4. Discuss whether the three large IOUs' 2024 ERRA proceedings should be consolidated for the sole purpose of addressing Fixed Generation Cost issues in the current proceeding(s) or in some separate phase(s).

SCE, Cal Advocates and Cal CCA filed opening comments in this proceeding. SCE, CalCCA, and DACC filed reply comments.

Cal Advocates and CalCCA called for the Commission to adopt a common definition of "fixed generation costs" either through a consolidated Track 2 ERRA process or a new proceeding that can address specific issues consistently

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[192] The last remaining bundled customer was intended to represent the "estimated cost that would remain if the investor-owned utility experienced load departure such that it had a single remaining bundled customer." (Ruling at 2).

across the three large IOUs. The reply comments filed by DACC agreed that the issue should be addressed consistently across the IOUs.[193]

SCE argued that the issues raised in the Ruling cannot be timely addressed in the 2024 ERRA forecast and argued that a consolidated Track 2 ERRA process could not effectively address the policy questions associated with determining a common definition of "fixed generation costs."

On October 9, 2023, the ALJ issued a Ruling finding the issues related to fixed generation costs cannot be addressed in this Decision, given the expedited ERRA forecast process necessary for SCE's 2024 rates to be implemented. Further consideration of SCE's fixed generation costs will therefore be addressed in a second track of this proceeding.

12. Future ERRA Forecast Application Requirements

SCE sought and received expedited treatment of its 2024 ERRA Forecast proceeding, which limited the timeframe for Commission and party review to six months. In its 2023 and 2024 ERRA Forecast Applications, SCE has requested a Commission decision by no later than the last voting meeting in November of each year. In the instant proceeding, SCE noted: "This timing will allow SCE to implement the adopted 2024 ERRA Forecast revenue requirement in its January 1, 2024, consolidated revenue requirement and rate change."[194]

Other IOUs have been able to implement their adopted ERRA Forecast revenue requirement in January after receiving a Commission decision on their applications during the second voting meeting in December.

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[193] Cal Advocates Opening Comments filed August 16, 2023 in A.23-06-001, A.23-05-012, and A.23-05-013; Cal CCA Opening Comments filed August 16, 2023 in A.23-06-001 and A.23-05-012 (at 2-11); San Diego Community Power and Clean Energy Alliance Opening Comments filed August 16, 2023 in A.23-05-013.

[194] Exhibit SCE-01C at 4.

In its next ERRA Forecast application, due in May 2024, SCE should explain in more detail:

1. Whether it still needs a full month to implement its billing schedules to reflect the adopted ERRA Forecast;
2. If so,
   a. Why it needs a full month to implement the adopted ERRA Forecast; and
   b. What changes to its billing system are necessary to shorten its necessary implementation time.

13. Safety Considerations

The California Legislature enacted AB 32 in part to address the health and safety impacts of GHG emissions, which pose "a serious threat to the economic well-being, public health, natural resources, and the environment of California." The Legislature found that GHG emissions could result in "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."[195]

This Decision approves SCE's forecast of GHG costs and allocation of GHG allowance proceeds because it helps achieve a main goal of AB 32 and Pub. Util. Code § 748.5 and will therefore improve the health and safety of California residents.

[195] AB 32 § 38501(a).

14. Compliance with the Authority Granted Herein

We authorize SCE to update the final 2023 year-end balances with recorded actuals through October 2023 and forecast for November and December 2023. If SCE has its November actuals available in time for submitting its Advice Letter, those should be included rather than a November forecast.

SCE shall submit a Tier 1 Advice Letter to the Commission's Energy Division within 30 days of the date of issuance of this Decision to implement the revenue requirements adopted in this Decision. The 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 further authorized to implement the revenue requirement adopted in this proceeding, as updated to reflect October – November 2023 actuals and forecasts for December 2023, in its advice letter for rates to be effective starting January 1, 2024.[196]

15. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

Fourteen comments on this proceeding were filed by 12 members of the public, each of which expressed concern that the rate decrease proposed by SCE

[196] If SCE's November 2023 actual numbers are not available at the time the utility files its implementation advice letter, it may use November 2023 forecasts.

in its 2024 ERRA Forecast will not occur because their electric rates have only increased in recent years. The public comments broadly opposed rate increases.

16. Reduction of Comment Period and Party Comments

The proposed Decision of ALJ Carolyn Sisto was mailed to parties on November 7, 2023, in accordance with Pub. Util. Code § 311. Comments were allowed under Rule 14.3. Pursuant to Rule 14.6(b); at the PHC, all parties stipulated to reduce the 30-day public review and comment period required by Pub. Util. Code § 311 to meet the procedural schedule requested by SCE.

Comments were filed by SCE and CalCCA on November 17, 2023, and reply comments were filed on November 22, 2023, by SCE and CalCCA. Clarifying edits were made throughout the Decision to address comments from both parties. Any comments on issues already addressed in earlier filings are not further discussed in this Decision.

17. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Carolyn Sisto is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

<u>2024 Forecast Overview and Methodology</u>

1. SCE's 2024 total forecast ERRA is $5.234 billion, which is a decrease of $325.830 million when compared to rates currently recovered from customers today.

2. SCE forecasted an increase in total retail electricity sales from a forecasted 82,966 GWh in 2023 to a forecast of 83,762 GWh in 2024.

3. SCE forecasted a 0.6 percent increase in its number of customers in both 2023 and 2024.

4. SCE's 2024 ERRA forecast included the projections of Direct Access (DA) and Community Choice Aggregator (CCA), for the entities that (1) filed a binding notice of intent to begin CCA service; (2) filed an initial RA filing; (3) started CCA service; and/or (4) formally submitted an April RA forecast pursuant to Pub. Util. Code Section 380.

SCE's Portfolio of Resources

5. SCE's forecast of utility-owned generation and purchased power contract deliveries in 2024 consisted of 1,176 MW nameplate capacity of hydroelectric power, 9 MW of nameplate capacity in solar photovoltaic resources, 10,071 MW from co-generation and renewable resources, 245 MW of natural gas peaker resources, and 1,056 MW from its Mountainview Generating Station.

6. SCE holds one (1) inter-utility contract for 2024, consisting of an entitlement of 117 MW of contingent capacity and 8 GWh of firm energy from the Hoover Dam project.

7. SCE forecasted costs for 6 GWh of energy reductions in 2024 to provide economic demand response programs, including the Summer Discount Plan, Capacity Bidding Program, Critical Peak Pricing, and Smart Energy Programs.

8. SCE forecasted a net increase of $47.018 million in procurement-related Public Purpose Program Charge funds to recover (1) behind-the-meter resources associated with its Preferred Resource Pilot #2 contracts; (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 forecasted F&PP costs associated with six types of contracts for new generation resources in 2024, 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 2024 system capacity requirements; and (6) Contracts used to meet local capacity requirements.

10. SCE forecasted 171,220,403 kWh of participation through the Green Tariff Shared Renewables program in 2024.

11. SCE forecasted $4.894 million in interim spent nuclear fuel costs at SONGS in 2024.

12. SCE forecasted $29.675 million in nuclear fuel expenses, and $0.0008 million in net interim spent nuclear fuel expenses at PVNGS in 2024.

13. SCE forecasted a total cost of $9.444 million to provide electricity service to Catalina Island, which includes $9.040 million in diesel fuel and $0.404 million for propane in 2024.

14. For 2024, SCE forecasted F&PP costs 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 forecasted 2024 hedging costs for energy-related transaction fees and option premiums for hedging SCE's open energy position in workpapers for 2024.

16. SCE holds a $3.35 billion multi-year revolving credit facility, also called the "revolver," to serve short-term borrowing requirements.

17. SCE forecasted costs associated with the revolving credit facility in workpapers for 2024, including: (1) $20,000 in administrative fees; (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.

18. SCE forecasted fuel inventory carrying costs for nuclear, natural gas, and diesel in workpapers for 2024.

19. SCE forecasted GHG procurement compliance carrying costs for 2024, which SCE estimated using historical GHG inventory balances and the ERRA BA interest rates in workpapers for 2024.

20. SCE forecasted the carrying costs associated with SCE's collateral requirements necessary to procure power in workpapers for 2024.

SCE's Revenue Requirement and Ratemaking Proposal

21. SCE's 2024 forecast bundled service customer rates are as follows:

Rate Schedule by Customer Group	Total Delivery (¢/kWh)	Total Generation (¢/kWh)	Total (¢/kWh)	% Change from 10/1/2023
Domestic				
• D	17.916	15.033	32.949	-3.9%
• D-CARE	5.386	15.031	20.417	-6.4%
• DE	9.768	15.026	24.794	-4.7%
• DM	5.695	15.060	20.755	-6.3%
• DMS-1	19.404	15.053	34.457	-0.7%
• DMS-2	19.361	15.080	34.441	-0.8%
Lighting-Small, Med. Power				
• GS-1	13.849	14.320	28.169	-3.0%
• GS-2	17.849	13.119	30.968	3.0%
• TC-1	21.507	11.653	33.160	2.7%
• TOU-GS	13.715	11.496	25.211	-4.8%
Large Power				
• TOU-S	11.942	10.909	22.851	-2.6%
• TOU-P	10.764	10.574	21.338	-1.1%
• TOU-T	4.079	9.635	13.714	-6.8%
• TOU-8-S-S	12.461	11.633	24.094	-3.0%
• TOU-8-S-P	12.270	11.117	23.388	-2.0%
• TOU-8-S-T	5.127	9.978	15.106	-4.6%
Agricultural & Pumping				
• TOU-PA-2	13.084	11.906	24.990	-9.3%
• TOU-PA-3	10.745	10.118	20.864	-2.7%
Street & Area Lighting				
• LS-1	43.784	7.965	51.749	1.3%
• LS-2	19.431	7.958	27.398	1.1%
• LS-3	8.229	7.973	16.202	-4.7%
• DTL	43.261	7.965	51.226	1.0%
• OL-1	33.831	7.965	41.796	0.7%
Average Rate — All Groups	13.227	12.912	26.139	-1.8%

22. SCE's 2024 forecast Generation Service revenue requirement is $5.513 billion, which will be allocated in balancing accounts as follows:

Description	**SCE Proposed 2024 Revenue Requirement**
2024 F&PP Costs (including GHG costs) • ERRA BA-related • PABA-related • Green Tariff Shared Renewables BA-related	 $4.459 billion $237.097 million $9.741 million
2023 ERRA BA True-up	$207.835 million
2023 PABA True-Up	$601.728 million
2023 Energy Settlement MA True-Up	-$380,000
Total Generation Service	**$5.513 billion**

23. The Green Tariff Shared Renewables BA forecast amount of $9.741 million for 2024 is accurate.

24. In total, SCE forecasted an overcollection of $380,000 in the Energy Settlement MA and Litigation Costs TA in 2023.

25. SCE should provide more transparent information about the updated usage amounts in the 12-CP allocator presented in Advice Letter 4831-E/E-A proposed in its 2024 ERRA forecast in the Advice Letter implementing this proceeding.

26. SCE identified some errors associated with how its Geysers Power contracts which resulted in the revenues received from CAISO for these contracts being recorded to the ERRA BA.

27. SCE's total 2024 forecast Delivery Service revenue requirement is negative $279.280 million, which will be allocated as follows:

Description	SCE Forecast 2024 Revenue Requirement (millions)
New System Generation • New System Generation F&PP 2024 Forecast[197] • Estimated 2023 YE NSGBA Balance • MCAM F&PP Forecast	 $402.996 $256.095 $1.313
Spent Nuclear Fuel Storage	$4.958
Distribution Rate Component • Base Revenue Requirement BA-Distribution F&PP • GHG Allowance Revenues	 -$3.582 -$955,105
Public Purpose Programs Charge • Public Purpose Program F&PP Charge 2024 Forecast • Tree Mortality Non-Bypassable Charge BA YE 2023 Balance • BioMAT Non-Bypassable Charge BA YE 2023 Balance	 $9.157 $10.588 -$6.689
Total Delivery Service	**-$279.280**

GHG Forecast Costs, Revenues and Reconciliation

28. SCE forecasted its 2023 GHG allowance revenue using a forecast proxy price of $39.36/MT.

29. SCE's net forecasted revenue proceeds from GHG allowances granted by CARB in 2024 is $932.108 million.

30. SCE's 2024 forecast administrative and customer outreach expenses to be set aside is $329,000 including FF&U.

31. SCE anticipates the IOUs' combined allocation of forecast GHG allowance auction proceeds for 2024 will exceed $1 billion.

32. SCE's GHG allocated allowance auction proceeds to be set aside for SOMAH program funding in 2024 is $46.528 million.

[197] Estimate includes indirect GHG costs.

33. SCE does not require GHG allocated allowance auction proceeds in 2024 for its DAC-GT and CSGT programs because it has sufficient funds set aside to cover forecast costs.

34. CPA's total 2024 program forecast for its DAC-GT and CSGT programs includes a net allocation of $26,769 from GHG allocated allowance auction proceeds in 2024.

35. Joint CCAs' total 2024 program forecast for its DAC-GT and CSGT programs includes a net allocation of $25,029 from SCE's GHG allocated allowance auction proceeds in 2024.

36. SCE has been previously authorized to allocate $20.4 million to implement the CEOP and is not requesting additional funding in 2024.

37. SCE's 2024 forecast EITE customer return is $58.834 million.

38. SCE's 2024 forecast semi-annual California Climate Credit is $86.00 per eligible residential and small commercial account, based on a forecast of 5,227,178 eligible recipients.

Cost Responsibility Surcharges

39. For 2024, CTC costs are as follows: (1) $0.00020/kWh for Domestic (D); (2) $0.00019/kWh for Street Lighting customers; (3) $0.00015/kWh for TOU-GS-1, TC-1, TOU-GS-2, and TOU-GS-2; $0.00014/kWh forTOU-8-Sec and TOU-8-Pri; $0.00015/kWh for TOU-PA-2, TOU-PA-3, and Standby-Sec; (4) $0.00143/kWh for Standby-Pri customers; and (5) $0.00013/kWh for and TOU-8-Sub and Standby-Sub customers of all vintages.

40. For 2024, the SCE Wildfire Non-Bypassable Charge will be the latest Commission-approved value for all customer classes in all vintages.

41. SCE's forecasted 2024 PCIA revenue requirement is as follows:

PCIA Revenue Requirement	**Amount (millions)**
Portfolio Cost	$4,110.980
Market Value • Energy Value • RPS Value • RA Value	-$4,884.941 -$2,576.107 -$860.117 -$1,448.717
One-Time Adjustments	-$380.0
Total 2024 Indifference Amount	-$774.341
Balancing Account True-Ups (no Uncollectibles Factor) • 2023 YE PABA Balance • 2023 GRC Memo Account (27-Month Amortization) • Remaining PUBA Balance to PABA • UOS Separator • 2023 YE ERRA Balance	 -$609.487 -$14.415 $2.948 $17.792 -$59.297
2024 PCIA Revenue Requirement	-$217.826
2024 PCIA Revenue Requirement with Uncollectibles Factor	-$218.219

42. SCE's forecasted 2024 PCIA rates by vintage are as follow:

2001	0.00000
2004	0.00000
2009	0.00050
2010	0.00141
2011	0.00295
2012	0.00318
2013	0.00264
2014	(0.00354)

2015	(0.00663)
2016	(0.00901)
2017	(0.00855)
2018	(0.00996)
2019	(0.01240)
2020	(0.01949)
2021	(0.01533)
2022	0.00270
2023	(0.00065)
2024	(0.00065)

43. SCE filed a PFM regarding D.23-06-006, as it relates to the valuation of RECs that were banked prior to the 2018 vintage, and how the value of pre-2019 banked RECs should apply across SCE's bundled and departing load customers.

44. SCE should retire RECs banked in or after 2019 to meet its forecasted bundled customer 2024 RPS compliance requirements to align with D.19-10-001 and the interim process adopted in D.22-12-012.

45. SCE should forecast the value of its UOS resources based on its updated methodology described in its October Update and Section 6.4.1 above, which reflects the cost of charging of UOS at SCE's forecasted off-peak pricing and the value of discharging at the Energy MPB at the time of discharge.

<u>Other</u>

46. SCE requested a Commission Decision on its 2024 ERRA Forecast by no later than November 30, 2023.

47. Challenges to facts supporting SCE's proposed 2024 forecast of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; and bundled customer electric sales and year-end balancing

accounts were waived by parties in this proceeding by virtue of stipulation to waive evidentiary hearing.

48. Given the expedited procedural schedule adopted for this Application, the issues raised in the August 1, 2023, ALJ Ruling related to fixed generation costs cannot be timely addressed in this Decision.

Conclusions of Law

1. SCE's 2024 forecast, as modified in this Decision, of F&PP prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; and bundled customer electric sales and year-end balancing account balances are reasonable.

2. SCE's proposed 2024 cost responsibility surcharges are reasonable and should be approved.

3. SCE should implement the revenue requirement adopted in this proceeding, as updated to reflect October – November 2023 actuals and forecasts for December 2023, in its advice letter for rates to be effective starting January 1, 2024.

4. SCE should address the issues associated with its Geysers Contracts Error in detail in its 2023 ERRA Compliance Review filing due on April 1, 2024.

5. SCE should retire RECs banked in or after 2019 to meet its 2024 RPS requirement as an interim process while its PFM to D.23-06-006 is considered by the Commission.

6. SCE should continue retiring pre-2019 banked RECs to comply with RPS in its 2025 ERRA Forecast Application until/unless its PFM to D.23-06-006 is resolved by the Commission.

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 regarding Track 1 issues described in Section 3 above should be confirmed.

9. The Commission orders adopted in D.23-04-012, authorizing SCE's 2023 ERRA Trigger Application (A.23-01-020) are unchanged by this Decision.

10. SCE's 2025 ERRA Forecast Application should provide a more detailed explanation of its billing system timing as it relates to implementing Commission-adopted ERRA Forecast Decisions.

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

12. Application 23-06-001 should remain open to address fixed generation cost issues.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is authorized to recover a total 2024 Energy Resource Recovery Account electric procurement cost revenue requirement forecast of $5.234 billion, consisting of both a generation service component and a delivery service component.

2. Within Southern California Edison Company's (SCE) 2024 generation service revenue requirement of $5.513 billion, SCE is authorized to recover a total of $4.459 billion in fuel and purchased power costs and transfer the following account balances: (1) $207.835 million from the Energy Resource Recovery Account (ERRA) Balancing Account (BA); (2) $601.728 million from the Portfolio Allocation BA; and (3) -$380,000 from the Energy Settlement Memorandum Account.

3. Within Southern California Edison Company's (SCE) 2024 delivery service revenue requirement of negative $279.280 million, SCE is authorized to recover the following: (1) $402.996 million for the New System Generation and System Reliability fuel and purchase power contracts; (2) $4.958 million in spent nuclear fuel costs; (3) -$3.582 million for forecast Base Revenue Requirement Balancing Account — Distribution fuel and purchased power costs; (4) -$955.105 million customer return of greenhouse gas allowance proceeds; and (5) $9.157 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 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.

4. Southern California Edison Company is authorized to transfer the following account balances: (1) a $256.095 million 2023 year-end balance in the New System Generation Balancing Account (BA); (2) $10.588 million in the 2023 year-end balance for the Tree Mortality Non-Bypassable Charge BA; and (3) -$6.689 million in the 2023 year-end BioMAT Non-Bypassable Charge BA.

5. Southern California Edison Company shall address the issues associated with its Geysers Contracts Error in detail in its 2023 Energy Resource Recovery Account Compliance Review filing due on April 1, 2024.

6. Southern California Edison Company (SCE) is authorized to reconcile its 2024 greenhouse gas (GHG) costs, revenues and requirements as follows: (1) recover a revenue requirement to cover the actual interest and forecasted carrying costs associated with its GHG Cap-and-Trade compliance; and (2) distribute $955.105 million in forecast 2024 GHG allowance auction proceeds to its customers, with $32.587 million set aside for clean energy and energy

efficiency projects, and $329,000 set aside for outreach and administrative expenses.

7. Southern California Edison Company (SCE) shall return $896.271 million in greenhouse gas allowance auction revenues to residential and small commercial customers through the forecasted amount of $86.00 in April and October 2024 for the California Climate Credit program.

8. Southern California Edison Company shall return a forecast of $58.834 million in greenhouse gas allowance auction revenues to its Emissions-Intensive and Trade-Exposed customers in April 2024.

9. Southern California Edison Company shall retire Renewable Energy Certificates (RECs) that were banked in or after 2019 to comply with its 2024 Renewables Portfolio Standard (RPS) requirements for bundled customers until or unless its RPS compliance burden exceeds its REC supply of 2019 or later vintage RECs.

10. Southern California Edison Company (SCE) 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 supporting documentation for:

(a) Residential rate schedules (including master-metered rate schedules) to include the authorized 2024 Climate Credit amount;

(b) Small business rate schedules to include the authorized 2024 Climate Credit amount;

(c) The updated October or November 2023 revenue requirement actuals and forecasts for November and/or December 2023, depending on the availability of November revenue requirement actuals at the time of the Advice Letter filing; and

(d) The usage of Renewable Energy Certificates banked in or after 2019 for 2024 Renewables Portfolio Standard compliance for SCE's bundled customers.

11. Southern California Edison Company's (SCE) request to keep its rates unchanged following Decision 23-04-012, authorizing SCE's 2023 Energy Resource Recovery Account Trigger Application is granted.

12. Southern California Edison Company must file a separate Tier 1 Consolidated Revenue Requirement and Rate Change Advice Letter no later than December 31, 2023, pursuant to Resolution E-5217. This Tier 1 Advice Letter must contain tariff sheet revisions as necessary to implement the rate changes authorized in this Decision.

13. In its 2025 Energy Resource Recovery Account (ERRA) Forecast Application, due in May 2024, Southern California Edison Company must explain in more detail:

1. Whether it still needs a full month to implement its billing schedules to reflect the adopted ERRA Forecast;
2. If so,

a. Why it needs a full month to implement the adopted ERRA Forecast; and
b. What changes to its billing system are necessary to shorten its necessary implementation time.

14. All rulings issued by the assigned Commissioner and Administrative Law Judge (ALJ) associated with Track 1 of Application (A.) 23-06-001) are affirmed herein; and all motions associated with Track 1 of A.23-06-001 not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, are denied.

15. Application 23-06-001 remains open to consider Fixed Generation Cost issues as raised in the August 1, 2023, and October 9, 2023, Administrative Law Judge Rulings.

This order is effective today.

Dated November 30, 2023, at Sacramento, California.

ALICE REYNOLDS
President
GENEVIEVE SHIROMA
DARCIE L. HOUCK
JOHN REYNOLDS
KAREN DOUGLAS
Commissioners

Appendix A
Glossary of Acronyms

Term	Acronym
Arizona Public Service Company	APS
Backbone Transportation Service	BTS
Balancing Account	BA
Base Revenue Requirement Balancing Account	BRRBA
Bioenergy Market Adjusting Tariff	BioMAT
BioMAT Non-Bypassable Charge	BMNBC
California Independent System Operator	CAISO
Capacity Bidding Program	CBP
Central Procurement Entity	CPE
Combined Heat-and-Power	CHP
Community Choice Aggregator	CCA
Community Solar Green Tariff	CSGT
Cost Allocation Mechanism	CAM
Cost Responsibility Surcharge	CRS
Customer Transition Cost	CTC
Demand Response	DR
Demand Response Program Balancing Account	DRPBA
Direct Access	DA
Disadvantaged Communities	DAC
Emissions-Intensive Trade-Exposed	EITE
Energy Efficiency	EE
Energy Resource Recovery Account	ERRA
Energy Service Providers	ESP
Energy Settlement Memorandum Account	ESMA
Enhanced Community Renewables	ECR
ERRA Balancing Account	ERRA BA
Franchise Fee and Uncollectible Factor	FF&U
Fuel and Purchase Power	F&PP
Gigawatt Hours	GWh
Green Tariff Shared Renewables Program	GTSR
Greenhouse Gas	GHG
Independent Spent Fuel Storage Installation	ISFSI
Kilowatt	kW
Kilowatt Hour	kWh
Least-Cost Dispatch	LCD
Litigation Costs Tracking Account	LCTA
Load Serving Entity	LSE
Local Capacity Requirement	LCR
Market Price Benchmark	MPB

Megawatt	MW
Mid-Term Reliability	MTR
Million British Thermal Units	MMBtu
Modified Cost Allocation Mechanism	MCAM
Net Energy Metering	NEM
New System Generation	NSG
Non-Bypassable Charge	NBC
Orange County Power Authority	OCPA
Palo Verde Nuclear Generation Station	PVNGS
PCIA Undercollection Balancing Account	PUBA
Petition for Modification	PFM
Portfolio Allocation Balancing Account	PABA
Power Charge Indifference Adjustment	PCIS
Preferred Resources Pilot	PRP
Proxy Demand Response	PDR
Public Purpose Program Charge	PPPC
Qualifying Facility	QF
Reliability Demand Response Resource	RDRR
Renewables Portfolio Standard	RPS
Request for Offers	RFO
Resource Adequacy	RA
Risk Assessment Management Phase	RAMP
San Onofre Nuclear Generating Station	SONGS
Smart Energy Program	SEP
Solar Photovoltaic	SPV
Southern California Edison	SCE
Standard Offer Contract	SOC
Summer Discount Plan	SDP
System Reliability Request for Offers	SRRFO
Tree Mortality Non-Bypassable Charge	TMNBC
Utility-Owned Generation	UOG
Utility-Owned Storage	UOS
Voluntary Market Allocation Offer	VAMO
Wildfire Non-Bypassable Charge	WF NBC
Year End	YE

(END OF APPENDIX A)